

12/87  
Nissen

# **INTERMOUNTAIN GENERATING STATION**

## **PERFORMANCE TEST REPORT**

**UNIT 2**  
**VOLUME 1**  
**TURBINE CYCLE**

**IPP**



**INTERMOUNTAIN POWER PROJECT**



**BLACK & VEATCH/engineers-architects**

**1987**

**IP14\_000796**

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## 1.0 INTRODUCTION

This report describes efficiency testing of power plant equipment for Intermountain Power Project Unit 2. It covers performance results, sample calculations, and data related to the eight test runs. The tests were conducted from May 11, 1987 through May 16, 1987. The unit was first synchronized in February 1987. The following groups of personnel assisted in and observed the tests.

Black & Veatch

General Electric

Intermountain Power Project Startup

Intermountain Power Service Corporation

Los Angeles Department of Water and Power

These tests were conducted to evaluate overall generating station and equipment performance. General Electric test data were used in determining the net turbine heat rate, condenser, feedwater heater, and boiler feed pump performance.

In addition to determining acceptability of equipment performance, the tests provide IPSC with bench mark data. Subsequent periodic tests on the unit can be compared with this bench mark data to reveal equipment wear or deterioration of performance from other causes.

## 2.0 SUMMARY AND CONCLUSIONS

### 2.1 TURBINE GENERATOR

The turbine-generator heat rate at 820 MW was determined by straight line interpolation between the corrected test heat rates for the third and fourth valve point tests and subtracting the differential heat rate between the straight line and design curve, in accordance with the contract. This resulted in a heat rate of 7,786 Btu/kWh, by the customer definition (1 percent condensate makeup), and is 0.5 percent better than the manufacturer's guarantee heat rate of 7,826 Btu/kWh. (Heat rates include power to booster boiler feed pumps.)

### 2.2 BOILER FEED PUMP TURBINES

The boiler feed pump turbines were not set at a specific valve point. This prevents finding corrections to calculate boiler feed pump turbine performance.

### 2.3 BALANCE OF PLANT

Data obtained from the above tests, along with concurrent station instrument data, were used to evaluate the performance of various equipment in the plant cycle, and to determine what equipment needs additional testing. The results are summarized as follows.

#### 2.3.1 Surface Condenser

While the hood pressures were excessive in earlier tests, the performance factors of heat transfer coefficient and cleanliness were deficient only in Hood B (IP Condenser 1B).

Higher than expected condenser hood pressures indicated air infiltration into the condenser. Leaks were located and eliminated or reduced for the final two turbine tests. Test 9, when compared with Test 3, exhibits substantially reduced pressures in Condenser Hoods A and B (HP Condenser 1A and IP Condenser 1B). It is most likely that the elimination of air infiltration will produce expected condenser performance.

### 2.3.2 Feedwater Heaters

All of the feedwater heaters with the exception of LP Heater 1C, which had high shell pressure readings, had better than guaranteed subcooler approach temperature differentials, and terminal temperature differentials closely comparable to guarantees.

### 2.3.3 Main Boiler Feed Pumps

The efficiencies of Boiler Feed Pumps 1A and 1B were 80.55 and 83.18 percent, respectively, as determined from the torque monitoring system data. Boiler Feed Pump 1B discharge pressure data was taken from the Information Computer. While it would appear that the guaranteed pump efficiency of 87 percent was not met, the test speeds for the pumps were significantly different from the rated speed. Further testing at the rated pump speed is required for accurate comparison.

### 3.0 TEST RESULTS

#### 3.1 GENERAL

General Electric test data and Information Computer data, when required, were used in the performance calculations. Test cycle heat balances, Figures 3-1 through 3-8, are based on heat balance calculations around the high-pressure heaters and deaerator, using a calibrated condensate flow section to determine boiler feedwater flow and subsequently main steam and reheat steam flows.

#### 3.2 TURBINE GENERATOR

The measure of the turbine-generator's performance is the net turbine heat rate. The turbine-generator performance was guaranteed on a "customer definition" heat rate basis. The customer heat rate was calculated by dividing the corrected heat input by the corrected generator output.

Table 3-1 is a summary of the customer definition turbine heat rates and corrected loads. Figure 3-9 shows the turbine heat rates determined from the tests and manufacturer's predicted heat rates. The test heat rates were corrected using ASME PTC 6.0 Group I and Group II corrections. The Group II correction curves are included in Section 6.0 of this report.

The test net heat rate is calculated by dividing the total heat input by the net generation. Figure 3-10 is a graphical representation of the test net heat rate versus net generation. There was no attempt to draw a curve through these data points due to data scatter. Lower heat rates are indicative of higher steam temperatures and pressures and lower condenser hood pressures. A summary of the test net heat rates is shown in Table 3-2.

Turbine stage efficiencies were determined by dividing the available energy in the steam by the isentropic expansion heat content of the steam. Table 3-3 shows a summary of the stage efficiencies for each test.

A Willins Curve, throttle flow versus gross generation, is shown on Figure 3-11. Table 3-4 shows a summary of the throttle flows and gross generator output.



### 3.3 CONDENSER

The condenser heat transfer coefficient is calculated by dividing the heat rejected from the condensate by the area of the surface condenser and the log mean temperature difference of the circulating water. This value is then corrected for circulating water inlet temperature. The cleanliness factor is found by comparing the actual corrected heat transfer coefficient with a manufacturer-defined minimum cleanliness heat transfer coefficient.

The heat transfer coefficient and cleanliness factor for each condenser hood were calculated for the VWO tests and are shown on Table 3-5 as a comparative tabulation of condenser performance.

### 3.4 FEEDWATER HEATERS

Heater performance is generally measured by the terminal difference and subcooler approach temperatures. Graphical representations of the heater performances which illustrate terminal difference and subcooler approach temperatures varying with load are shown in Figures 3-12 through 3-22.

Table 3-6 shows the comparative closed feedwater heater performance. A summary of the terminal difference and subcooler approach temperatures is shown in Table 3-7.

### 3.5 BOILER FEED PUMPS

Boiler feed pump efficiency is calculated by multiplying the developed head by the volumetric flow and specific gravity of the water pumped and dividing by the horsepower input and appropriate conversion factors. Relative performance is calculated by dividing the corrected developed head by the expected developed head. Expected developed head is a function of corrected volumetric flow. Information Computer pump discharge pressure for Boiler Feed Pump 1B was used in the calculations.

Table 3-8 is a comparative tabulation of boiler feed pump performance. Table 3-9 provides a summary of the pump efficiencies and relative performance for the tests.

### 3.6 FEEDWATER FLOW NOZZLE VERSUS CONDENSATE FLOW NOZZLE

ASME PTC 6.1 provides an alternative testing procedure to determine turbine heat rate. Instead of measuring the condensate flow and calculating the feedwater flow, a flow element in the feedwater line after the final feedwater heater is used to directly compute the feedwater flow. It has been shown that this is an acceptable, less expensive method, due to fewer, less precise measurements.

Test heat rates for the full ASME test and for the feedwater flow nozzle measurements were calculated and are shown in Table 3-10. For most of the tests, the difference between the heat rates determined from the feedwater flow nozzle as compared to the heat rates determined from the condensate flow nozzle are within the 1/3 percent uncertainty expected in PTC 6.1.

TABLE 3-1. ONE PERCENT MAKEUP CORRECTED HEAT RATES

	<u>Corrected Heat Rate, Btu/kWh</u>	<u>Corrected Load, kW</u>
VWO	7779.3	873,212
3rd VP	7795.8	794,888
2nd VP	7923.2	598,149

Interpolated Heat Rate

at 820 MW = 7,786 Btu/kWh

Guaranteed Heat Rate

at 820 MW = 7,826 Btu/kWh

Note: Includes booster boiler feed pump power.

TABLE 3-2. TEST NET HEAT RATE VERSUS NET LOAD

<u>Test</u>	<u>Test HR, Btu/kWh</u>	<u>Net Load, kW Measured</u>
8	8,254	848,120
4	8,384	809,939
6	8,330	812,736
5	8,382	738,619
7	8,392	728,514
10	8,169	752,881
3	8,562	552,196
9	8,277	563,773

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TABLE 3-3. TURBINE EFFICIENCY

<u>Test</u>	<u>High Pressure, Percent</u>	<u>Intermediate Pressure, Percent</u>	<u>Low Pressure (ELEP), Percent</u>
8	88.02	92.71	93.21
4	88.19	92.80	92.61
6	88.33	92.51	93.06
5	86.49	92.58	92.62
7	86.55	92.71	92.73
10	86.47	92.59	92.79
3	81.78	93.78	92.72
9	81.68	92.36	93.76

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TABLE 3-4. THROTTLE FLOW VERSUS GROSS GENERATION

<u>Test</u>	<u>Gross Generation, kW</u>	<u>Throttle Flow, lb/h</u>
8	898,360	6,495,805
4	859,949	6,220,846
6	860,776	6,221,229
5	785,541	5,568,489
7	775,094	5,478,699
10	789,291	5,473,079
3	592,046	4,046,000
9	599,733	3,976,634

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TABLE 3-5. COMPARATIVE CONDENSER PERFORMANCE

	<u>Test*</u>	<u>Guarantee</u>
Pressure (in. Hg)		
Condenser 1A	4.31	3.36
Condenser 1B	4.15	2.80
Condenser 1C	2.65	2.34
Heat Transfer Coefficient (Btu/h-ft <sup>2</sup> -F)		
Condenser 1A	576.31	558.8
Condenser 1B	391.61	539.3
Condenser 1C	607.82	539.3
Cleanliness Factor (percent)		
Condenser 1A	95.55	85
Condenser 1B	64.81	85
Condenser 1C	100.59	85

\*VWO

TABLE 3-6. COMPARATIVE FEEDWATER HEATER PERFORMANCE

LOW-PRESSURE HEATERS

	<u>Design</u>	<u>Test</u>
<u>Heaters 1A, 1B, and 1C</u>		
Condensate Flow, lb/h	5,254,771	4,526,700
Shell Pressure, psia	4.51	4.86*
Steam to Heater, lb/h	169,144	120,335
Enthalpy of Steam, Btu/lb	1,100.9	1,090
Terminal Difference, F	2.0	0.29*
Subcooler Approach, F	5.0	5.26
Subcooler Flow, lb/h	920,818	564,152

\*Does not include Heater 1C.

<u>Heater 2</u>		
Condensate Flow, lb/h	5,254,771	4,526,700
Shell Pressure, psia	10.7	11.07
Steam to Heater, lb/h	178,238	142,336
Enthalpy of Steam, Btu/lb	1,142.5	1,163.0
Terminal Difference, F	2.0	2.15
Subcooler Approach, F	10	7.87
Subcooler Flow, lb/h	573,462	421,816

<u>Heater 3</u>		
Condensate Flow, lb/h	6,127,017	4,526,700
Shell Pressure, psia	37.7	38.05
Steam to Heater, lb/h	378,723	279,958
Enthalpy of Steam, Btu/lb	1,236.2	1,244.9
Terminal Difference, F	2.0	-0.03
Subcooler Approach, F	10	8.74
Subcooler Flow, lb/h	194,754	141,522

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TABLE 3-6 (Continued). COMPARATIVE FEEDWATER HEATER PERFORMANCE

## LOW-PRESSURE HEATERS (Continued)

	<u>Design</u>	<u>Test</u>
<u>Heater 4</u>		
Condensate Flow, lb/h	6,127,017	4,526,700
Shell Pressure, psia	63.2	63.5
Steam to Heater, lb/h	194,754	141,859
Enthalpy of Steam, Btu/lb	1,282.3	1,291.6
Terminal Difference, F	2.0	-0.23
Subcooler Approach, F	10	4.78
Subcooler Flow, lb/h	—	—

## HIGH-PRESSURE HEATERS

Heaters 6A and 6B

Feedwater Flow, lb/h	6,513,490	6,221,038
Shell Pressure, psia	230.6	230.1
Steam to Heater, lb/h	239,944	234,886
Enthalpy of Steam, Btu/lb	1,419.8	1,426.5
Terminal Difference, F	-2.0	-1.33
Subcooler Approach, F	10	7.79
Subcooler Flow, lb/h	1,203,812	1,134,309

Heaters 7A and 7B

Feedwater Flow, lb/h	6,513,490	6,221,038
Shell Pressure, psia	584.3	557.5
Steam to Heater, lb/h	610,344	550,173
Enthalpy of Steam, Btu/lb	1,306.6	1,305.9
Terminal Difference, F	-1.0	-0.60
Subcooler Approach, F	10	9.26
Subcooler Flow, lb/h	593,470	584,136

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TABLE 3-6 (Continued). COMPARATIVE FEEDWATER HEATER PERFORMANCE

HIGH-PRESSURE HEATERS (Continued)

	<u>Design</u>	<u>Test</u>
<u>Heaters 8A and 8B</u>		
Feedwater Flow, lb/h	6,513,490	6,221,038
Shell Pressure, psia	1,061	1,063.8
Steam to Heater, lb/h	593,470	584,136
Enthalpy of Steam, Btu/lb	1,369.2	1,379.2
Terminal Difference, F	-2.0	-0.20
Subcooler Approach, F	10	7.22
Subcooler Flow, lb/h	—	—

TABLE 3-7. FEEDWATER HEATER TEST RESULTS

LOW-PRESSURE HEATERS

<u>Test</u>	<u>Heater 1A, TD</u>	<u>Heater 1B, TD</u>	<u>Heater 1C, TD</u>	<u>Heater 1, SA</u>
8	0.36	0.36	7.03	6.23
4	0.30	0.31	3.33	5.07
6	0.29	0.25	5.35	5.45
5	0.30	0.21	5.58	4.76
7	0.38	0.27	8.19	4.49
10	0.35	0.25	9.81	5.68
3	0.63	0.26	5.51	2.17
9	0.40	0.23	15.83	3.26

<u>Test</u>	<u>Heater 2</u>		<u>Heater 3</u>		<u>Heater 4</u>	
	<u>TD</u>	<u>SA</u>	<u>TD</u>	<u>SA</u>	<u>TD</u>	<u>SA</u>
8	2.27	8.18	0.10	8.93	0.02	5.03
4	2.16	7.83	-0.05	8.73	-0.17	4.76
6	2.13	7.90	-0.01	8.74	-0.28	4.79
5	1.95	7.45	-0.48	8.26	-0.49	4.11
7	1.94	7.31	-0.46	8.15	-0.55	4.09
10	2.01	7.57	-0.22	8.35	-0.48	4.22
3	1.78	-4.64*	-1.08	6.78	-0.94	3.12
9	1.82	-6.16*	-1.12	6.81	-1.08	3.13

\*Heater 2 alternate drains to condenser.

TABLE 3-7 (Continued). FEEDWATER HEATER TEST RESULTS

## HIGH-PRESSURE HEATERS

Test	Heater 6A		Heater 6B		Heater 7A		Heater 7B	
	<u>TD</u>	<u>SA</u>	<u>TD</u>	<u>SA</u>	<u>TD</u>	<u>SA</u>	<u>TD</u>	<u>SA</u>
8	-0.87	7.75	-0.72	8.40	-0.16	9.72	0.86	8.60
4	-1.45	7.54	-1.30	8.08	-1.04	9.35	-0.24	10.17
6	-1.33	7.51	-1.22	8.03	-0.98	9.25	-0.15	8.26
5	-2.29	6.78	-2.08	7.28	-1.86	8.26	-1.17	7.42
7	-2.39	6.75	-2.15	6.99	-2.05	8.16	-1.33	7.30
10	-3.10	6.67	-2.60	7.19	-2.11	8.23	-1.17	6.85
3	-3.62	5.45	-3.97	5.53	-2.24	6.31	-2.37	5.66
9	-3.82	5.02	-3.86	5.63	-2.99	6.11	-2.41	5.47

Test	Heater 8A		Heater 8B	
	<u>TD</u>	<u>SA</u>	<u>TD</u>	<u>SA</u>
8	1.78	7.63	0.64	7.67
4	0.35	7.23	-0.81	7.23
6	0.42	7.18	-0.74	7.22
5	-1.47	6.27	-2.74	6.18
7	-1.69	6.17	-2.73	5.75
10	-1.81	6.23	-3.01	6.19
3	-3.99	5.20	-5.16	4.28
9	-4.13	4.42	-5.25	4.12

TABLE 3-8. COMPARATIVE BOILER FEED PUMP PERFORMANCE

	<u>Guarantee</u>	<u>Boiler Feed Pump 1A</u>	<u>Boiler Feed Pump 1B</u>
Capacity, gpm	7,700	7,153	7,728
Total Head, feet	8,000	7,816	7,715
Efficiency, percent	87.0	80.55	83.18
Brake Horsepower, bhp	15,562	12,351	13,186
Pump Speed, rpm	5,750	5,295	5,353
Relative Performance	1.0	0.774	0.832

Note: Boiler Feed Pump 1B results derived from station data pump discharge pressure.

TABLE 3-9. TURBINE DRIVEN BOILER FEED PUMPS

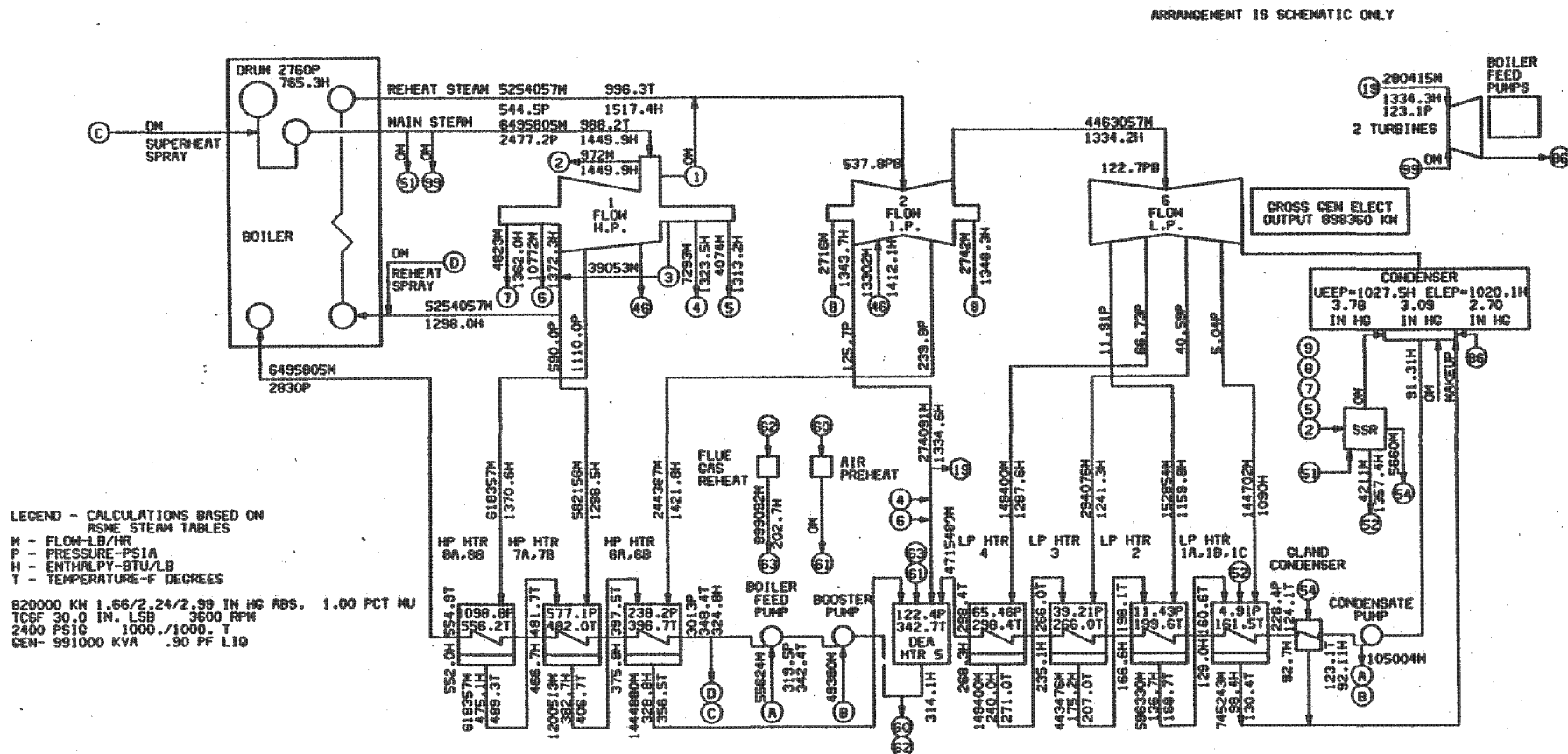
<u>Test</u>	<u>Boiler Feed Pump 1A Efficiency, Percent</u>	<u>Boiler Feed Pump 1A Relative Performance</u>	<u>Boiler Feed Pump 1B Efficiency, Percent</u>	<u>Boiler Feed Pump 1B Relative Performance</u>
8	80.15	0.817	82.61	0.876
4	80.58	0.774	83.18	0.831
6	80.51	0.774	83.17	0.832
5	82.15	0.715	84.47	0.751
7	81.77	0.692	84.27	0.726
10	81.06	0.692	82.71	0.728
3	80.43	0.616	88.44	0.644
9	81.29	0.606	88.70	0.637

TABLE 3-10. TEST HEAT RATE

<u>Test</u>	<u>Feedwater Nozzle Btu/kWh</u>	<u>Condensate Nozzle Btu/kWh</u>	<u>Error, Percent</u>
8	7,796	7,792	0.05
4	7,905	7,897	0.10
6	7,881	7,865	0.20
5	7,877	7,877	0.00
7	7,889	7,887	0.03
10	7,665	7,792	1.63
3	8,024	7,985	0.49
9	7,783	7,781	0.03

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FIGURE 3-1



$$\text{TEST HEAT RATE} = \frac{6495805(1449.9-552.0) + 6495805(1.45) + 4820484(92.1-91.3) + 5254057(1517.4-1298.0) + 6496(765.3-552.0)}{898360KH} = 7792 \frac{BTU}{KH \text{ HR}}$$

$$\text{CORRECTED CUSTOMER DEFINED} = 7723 \frac{BTU}{KH \text{ HR}} \text{ 1\% MU HEAT RATE}$$

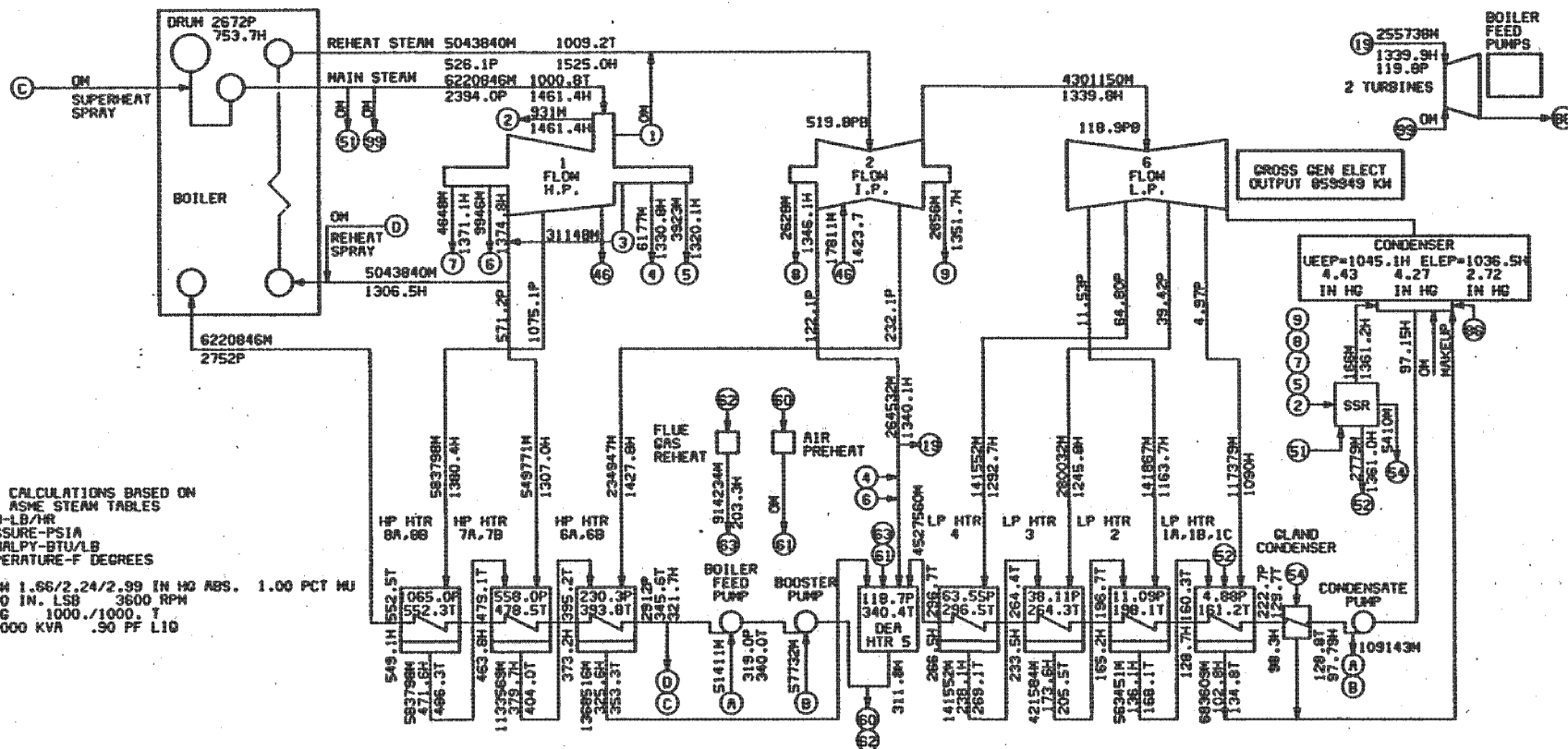
INTERMOUNTAIN POWER AGENCY  
INTERMOUNTAIN POWER PROJECT UNIT 2  
TEST 8 - VMO 5% OVERPRESSURE HEAT BALANCE



FIGURE 3-2

LEGEND - CALCULATIONS BASED ON  
ASME STEAM TABLES  
M - FLOW-LB/HR  
P - PRESSURE-PSIA  
H - ENTHALPHY-BTU/LB  
T - TEMPERATURE-F DEGREES

820000 KW 1.66/2.24/2.99 IN HG ABS. 1.00 PCT MU  
TC6F 30.0 IN. L58 3600 RPM  
2400 PSIG 1000./1000. T  
GEN- 991000 KVA .90 PF L10



ARRANGEMENT IS SCHEMATIC ONLY

$$\text{TEST HEAT RATE} = \frac{6220846(1461.4-549.1) + 6220846(1145.7-97.2) + 5043840(1525.0-1306.5) + 6220(753.7-549.1)}{859949 \text{ KW}} = 7897 \frac{\text{BTU}}{\text{KW HR}}$$

$$\text{CORRECTED CUSTOMER DEFINED} = 7785 \frac{\text{BTU}}{\text{KW HR}} \text{ 1\% MU HEAT RATE}$$

INTERMOUNTAIN POWER AGENCY  
INTERMOUNTAIN POWER PROJECT UNIT 2  
TEST 4 - VWO HEAT BALANCE

FIGURE 3-3

LEGEND - CALCULATIONS BASED ON  
ASME STEAM TABLES

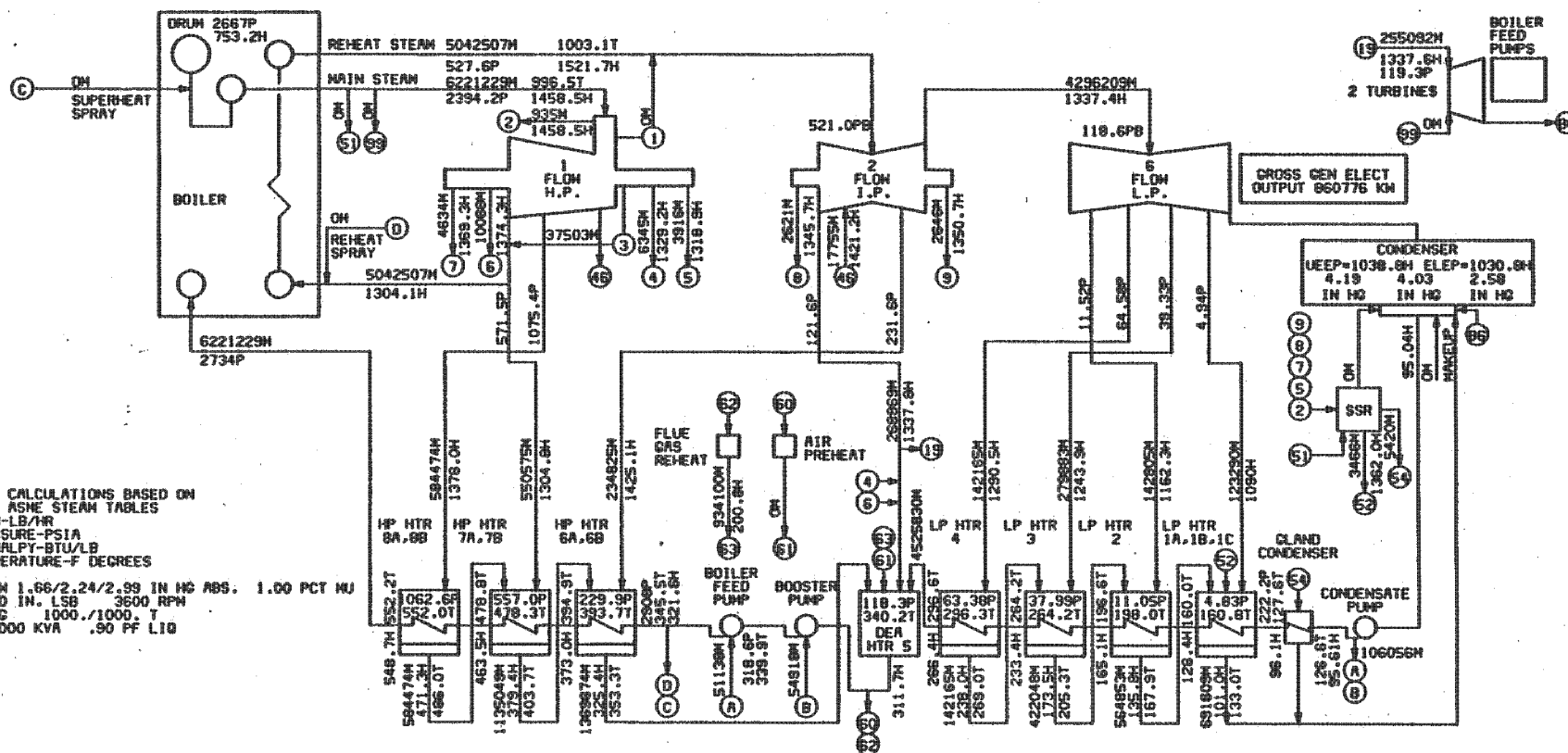
M - FLOW-LB/HR  
P - PRESSURE-PSIA  
H - ENTHALPHY-BTU/LB  
T - TEMPERATURE-F DEGREES

920000 KM 1.66/2.24/2.99 IN H<sub>2</sub> ABS. 1.00 PCT MU  
1C6F 30.0 IN. LSB 3600 RPN  
2400 PSIG 1000./1000. T  
GEN- 991000 KVA .90 PF L10

$$\text{TEST HEAT RATE} = \frac{6221229(1458.5-548.7) + 6221229(1.45) + 4631886(95.8-95.0) + 5042507(1521.7-1304.1) + 6221753.2-548.7}{860776\text{KM}} = 7865 \frac{\text{BTU}}{\text{KM HR}}$$

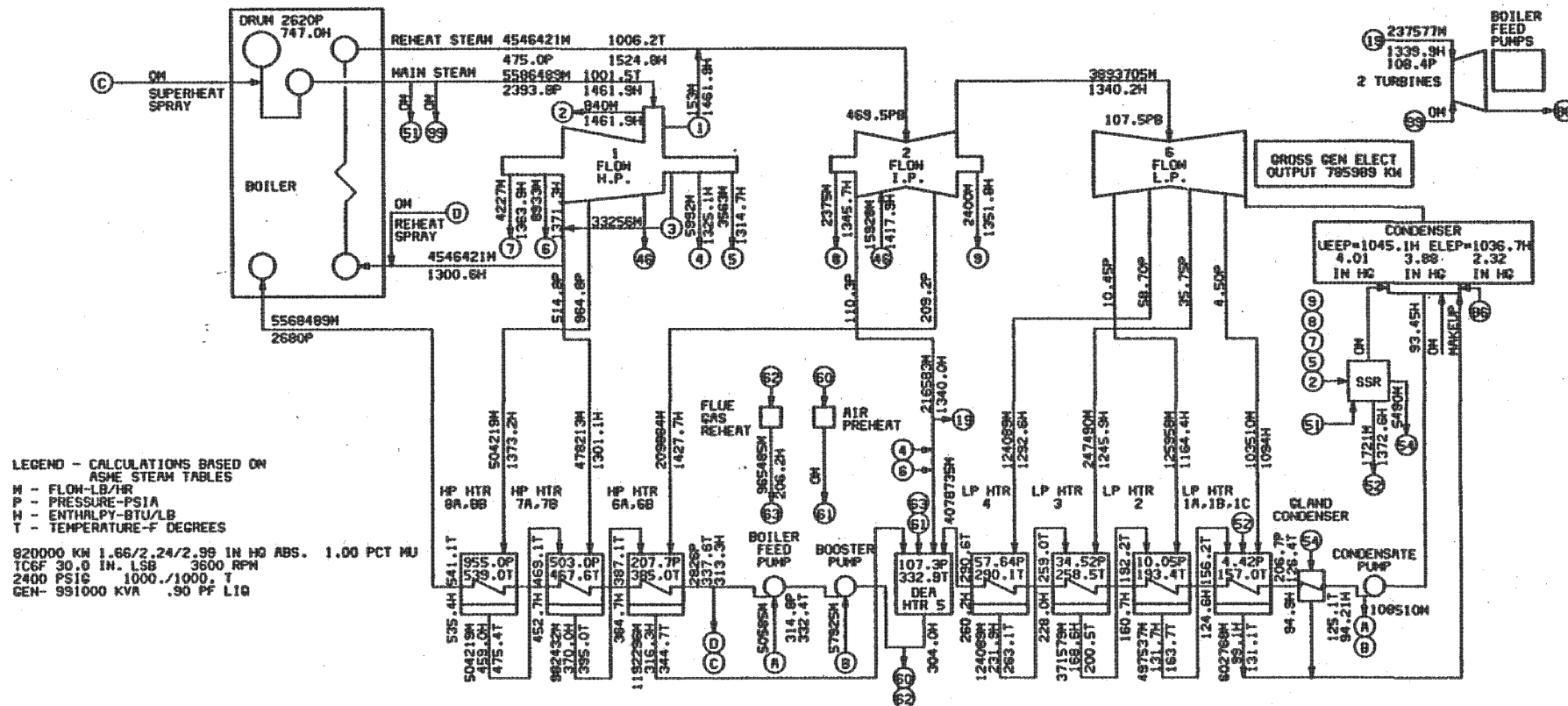
$$\text{CORRECTED CUSTOMER DEFINED} = 7774 \frac{\text{BTU}}{\text{KM HR}} \text{ 1X MU HEAT RATE}$$

ARRANGEMENT 16 SCHEMATIC ONLY



INTERMOUNTAIN POWER AGENCY  
INTERMOUNTAIN POWER PROJECT UNIT 2  
TEST 6 - VMO HEAT BALANCE

FIGURE 3-4



ARRANGEMENT IS SCHEMATIC ONLY

LEGEND - CALCULATIONS BASED ON  
ASME STEAM TABLES  
H - FLOW-LB/HR  
P - PRESSURE-PSIA  
H - ENTHALPY-BTU/LB  
T - TEMPERATURE-F DEGREES

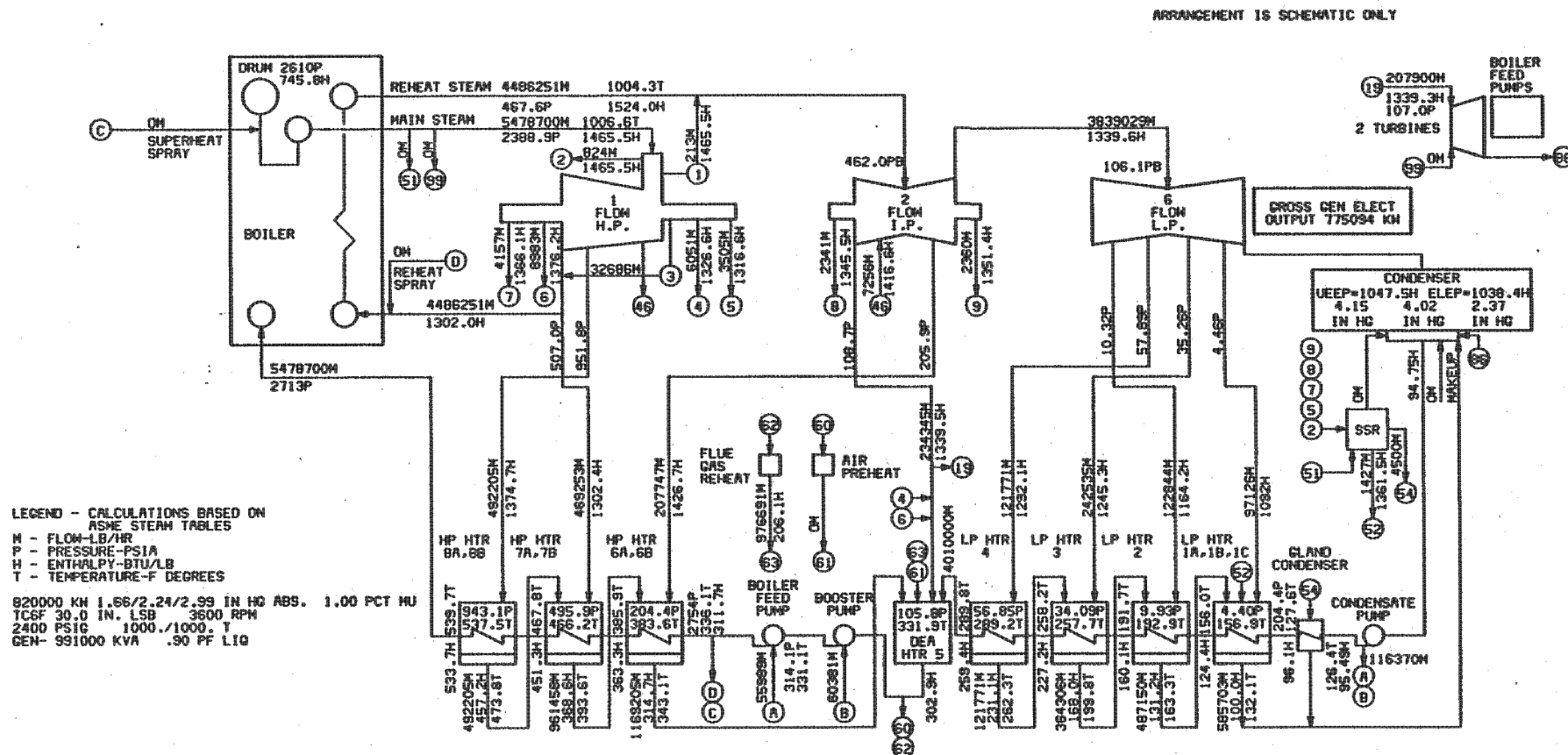
920000 KW 1.66/2.24/2.99 IN HQ ABS. 1.00 PCT MU  
TC6F 30.0 IN. LSB 3600 RPM  
2400 PSIG 1000./1000. T  
GEN- 991000 KVA .90 PF LIG

TEST HEAT RATE =  $\frac{5568489(1461.9-535.4)+5568489(1.50)+4187245(94.2-93.4)+4546421(1524.8-1300.6)+5568(747.0-535.4)}{785989KW}$  = 7877 BTU/KW HR

CORRECTED CUSTOMER DEFINED = 7804 BTU/KW HR  
1X MU HEAT RATE

INTERMOUNTAIN POWER AGENCY  
INTERMOUNTAIN POWER PROJECT UNIT 2  
TEST 5 - THIRD VALVE POINT HEAT BALANCE

FIGURE 3-5



TEST HEAT RATE =  $\frac{5478700(1465.5-533.7)+5478700(1.50)+4126370(95.5-94.8)+4486251(1524.0-1302.0)+5479(745.8-533.7)}{775094\text{KW}}$  = 7887 BTU/KW HR  
CORRECTED CUSTOMER DEFINED 1% MU HEAT RATE = 7796 BTU/KW HR

INTERMOUNTAIN POWER AGENCY  
INTERMOUNTAIN POWER PROJECT UNIT 2  
TEST 7 - THIRD VALVE POINT HEAT BALANCE

FIGURE 3-6

LEGEND - CALCULATIONS BASED ON  
ASME STEAM TABLES

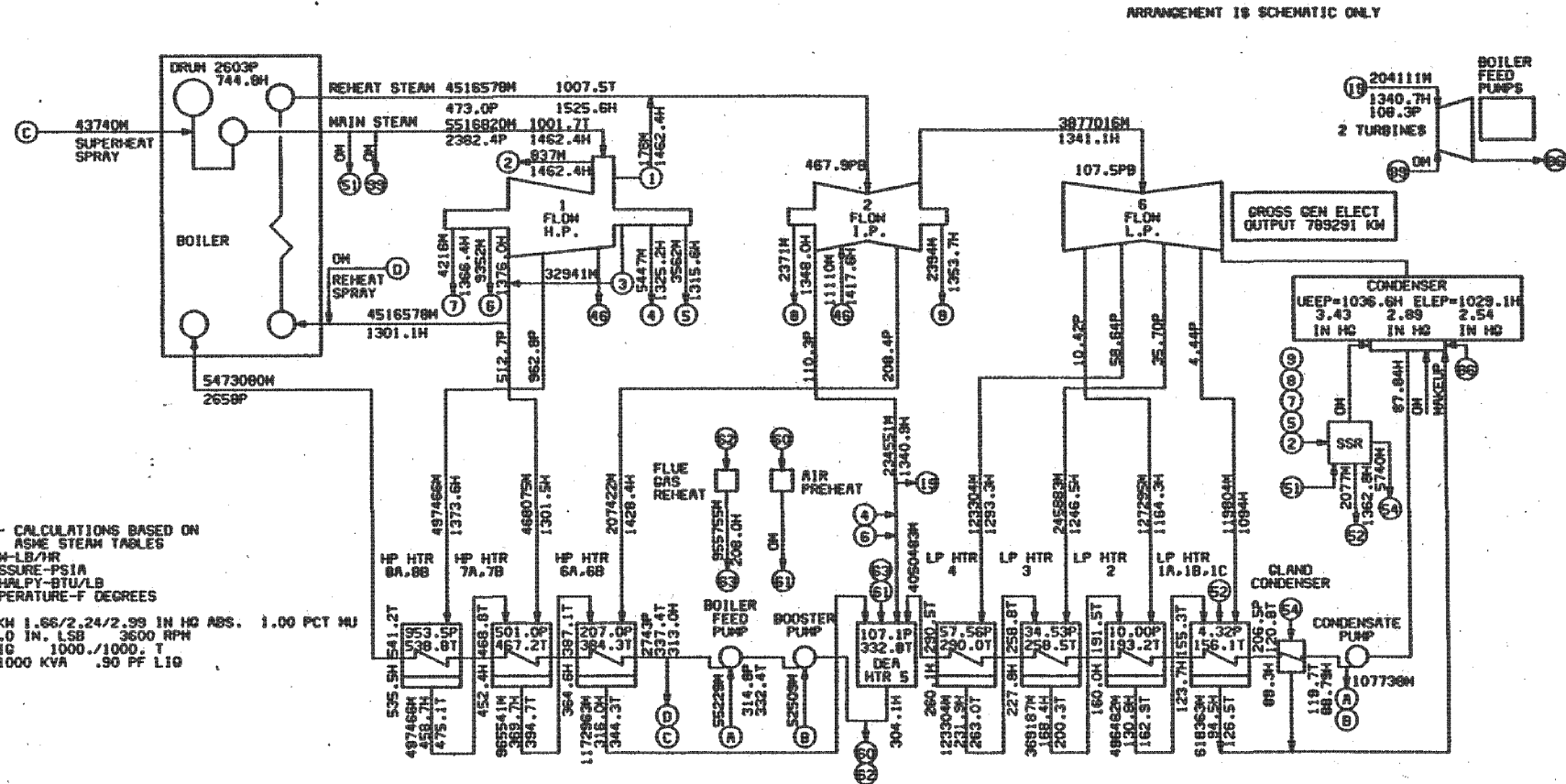
M - FLOW-LB/HR  
P - PRESSURE-PSIA  
H - ENTHALPY-BTU/LB  
T - TEMPERATURE-F DEGREES

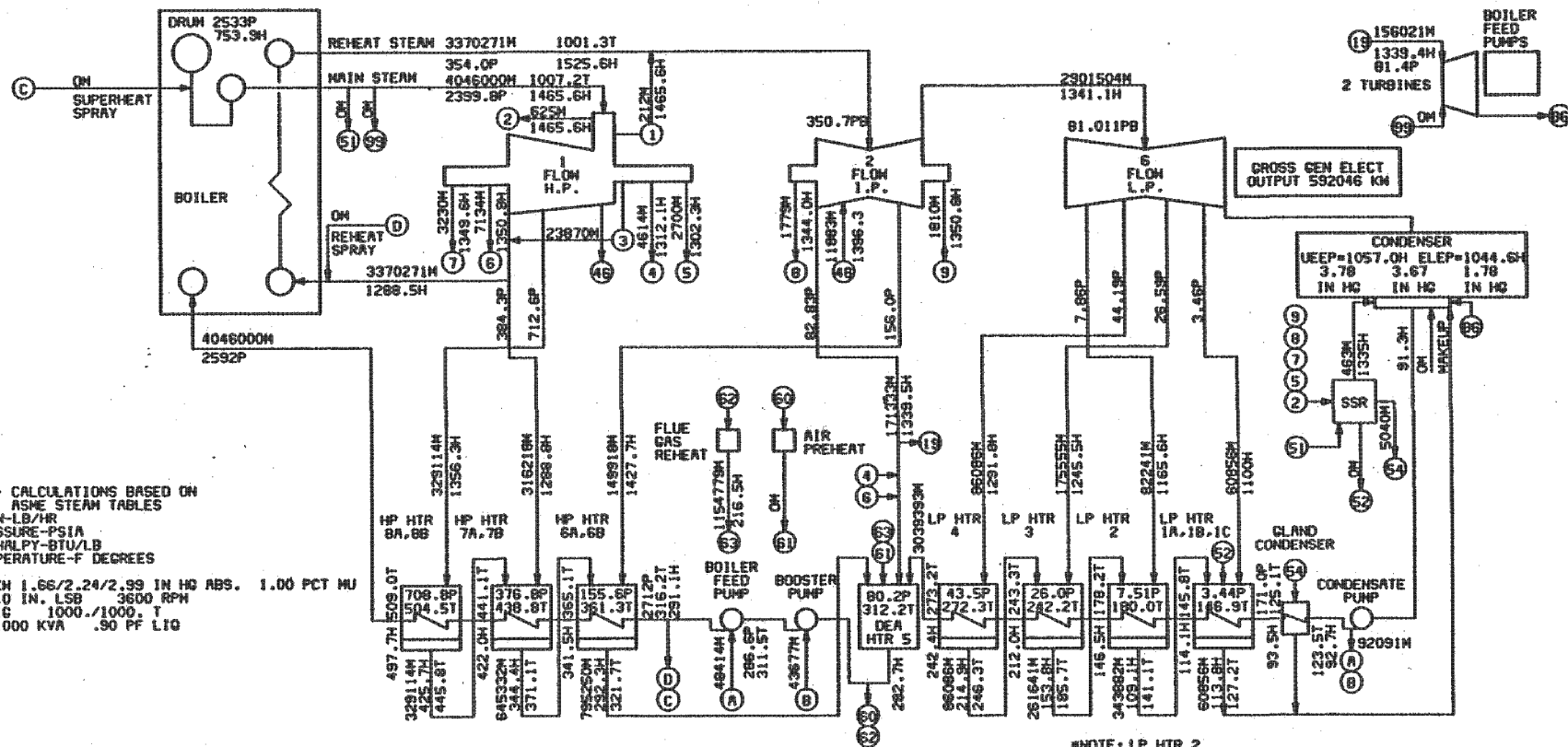
820000 KM 1.66/2.24/2.99 IN HG ABS. 1.00 PCT MU  
TC&F 30.0 IN. LSB 3600 RPM  
2400 PSIG 1000./1000. T  
GEN- 991000 KVA .90 PF L10

$$\text{TEST HEAT RATE} = \frac{5473080(1462.4-535.5)+43740(1462.4-313.0)+5516820(1150)+4158221(88.8-87.8)+4516578(1525.6-1301.1)+5473(1744.8-535.5)}{789291\text{KM}} = 7792 \frac{\text{BTU}}{\text{KM HR}}$$

CORRECTED CUSTOMER DEFINED = 7788 BTU  
1% MU HEAT RATE KM HR

INTERMOUNTAIN POWER AGENCY  
INTERMOUNTAIN POWER PROJECT UNIT 2  
TEST 10 - THIRD VALVE POINT HEAT BALANCE





ARRANGEMENT IS SCHEMATIC ONLY

LEGEND - CALCULATIONS BASED ON  
ASME STEAM TABLES  
H - FLOW-LB/HR  
P - PRESSURE-PSIA  
H - ENTHALPY-BTU/LB  
T - TEMPERATURE-F DEGREES

820000 KH 1.66/2.24/2.99 IN HQ ABS. 1.00 PCT MU  
TC8F 30.0 IN. LSB 3600 RPH  
2400 PSIG 1000./1000. T  
GEN- 931000 KVA .90 PF LIG

\*NOTE: LP HTR 2  
DRAIN TO CONDENSER

$$\text{TEST HEAT RATE} = \frac{4046000(1465.6-497.7)+4046000(1.77)+3131484(92.7-91.3)+3370271(1525.6-1288.5)+40461735.9-497.7}{592046\text{KH}} = 7985 \frac{\text{BTU}}{\text{KH HR}}$$

CORRECTED CUSTOMER DEFINED = 7920  $\frac{\text{BTU}}{\text{KH HR}}$   
1% MU HEAT RATE

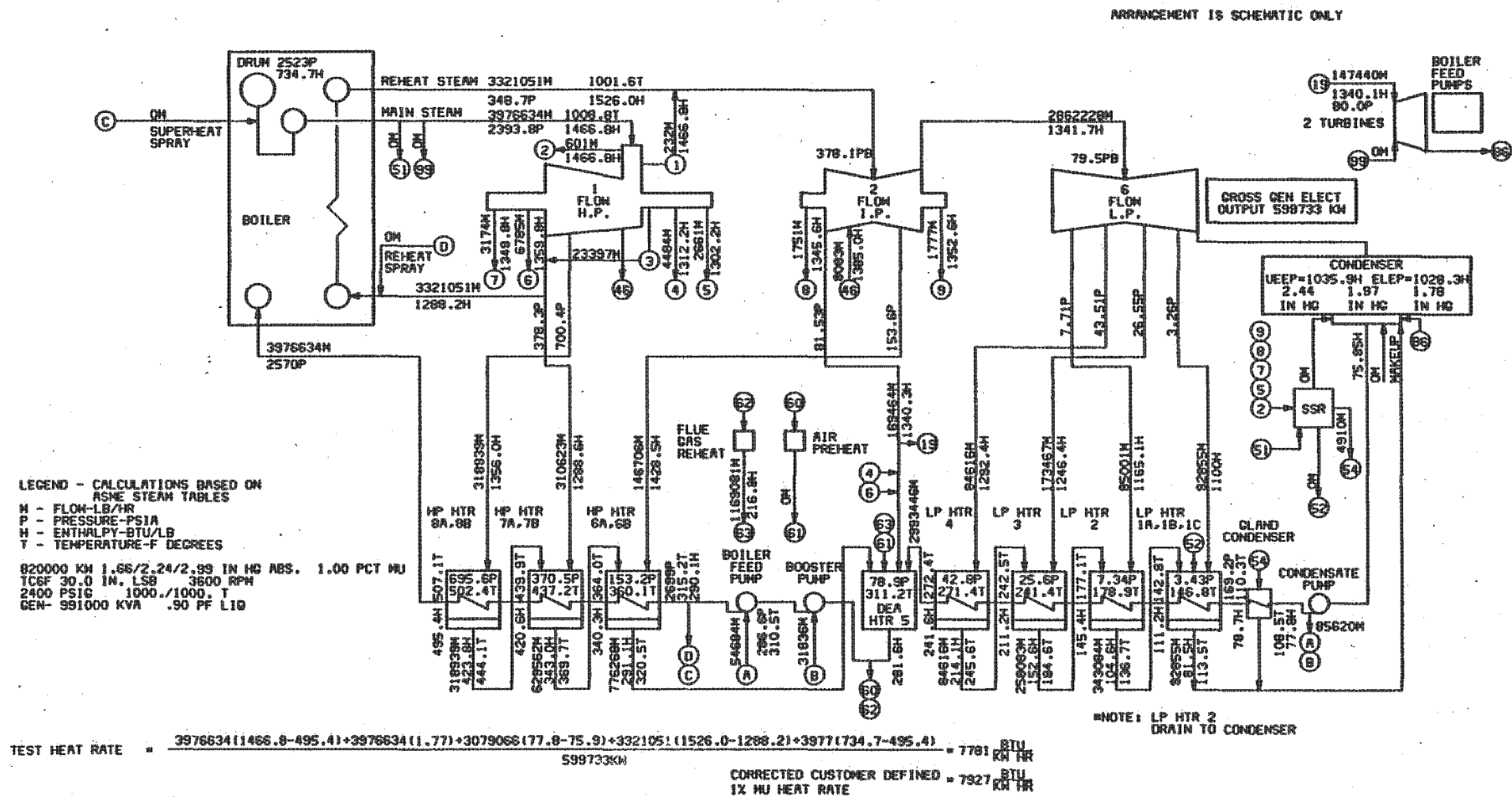
INTERMOUNTAIN POWER AGENCY  
INTERMOUNTAIN POWER PROJECT UNIT 2

TEST 3 - SECOND VALVE POINT HEAT BALANCE

FIGURE 3-7

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FIGURE 3-8



NET HEAT RATE (BTU/KWHR)  
(CUSTOMER DEFINITION, 1% MAKEUP)

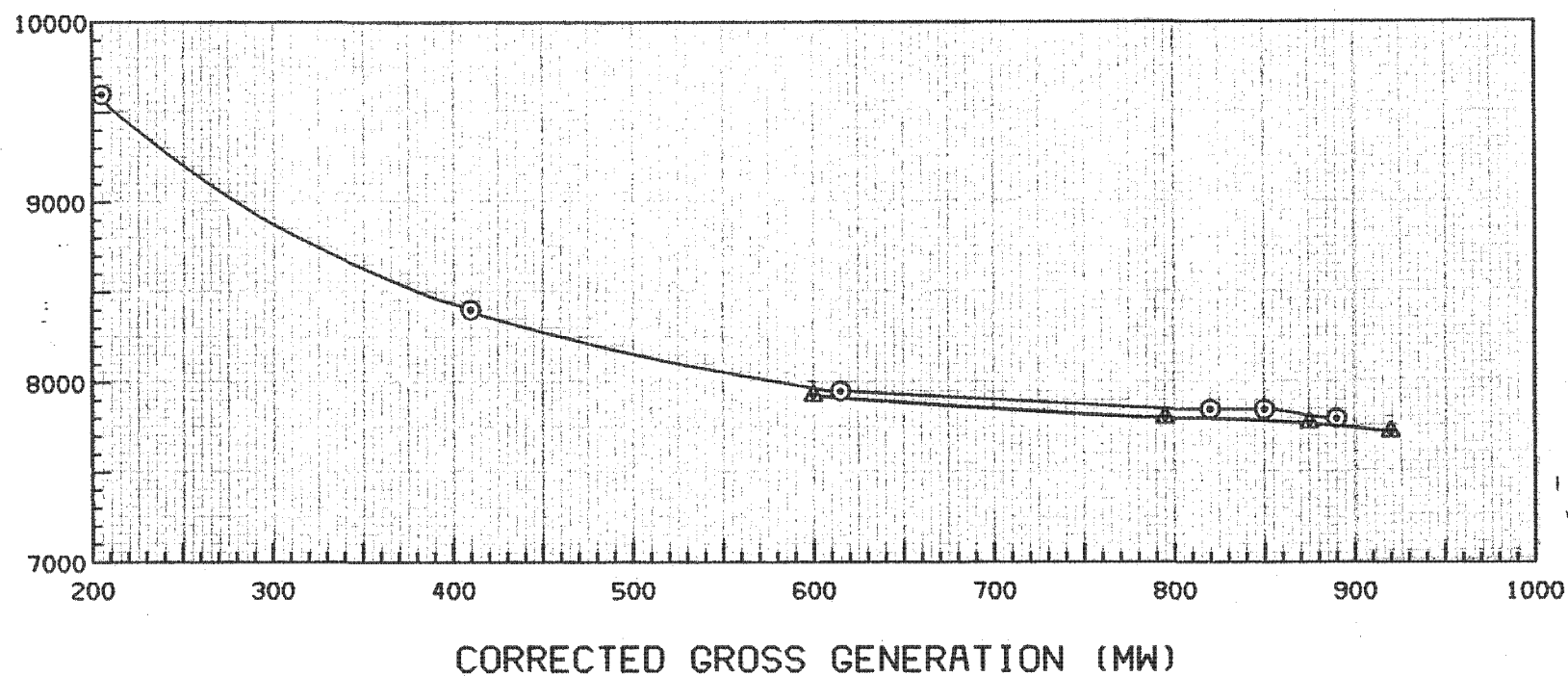


FIGURE 3-9: CORRECTED NET HEAT RATE  
INTERMOUNTAIN POWER AGENCY  
IPP UNIT 2

KEY:

- 1% MU HEAT BALANCE
- ▲ B&V CALCULATED HEAT RATE, 1% MU



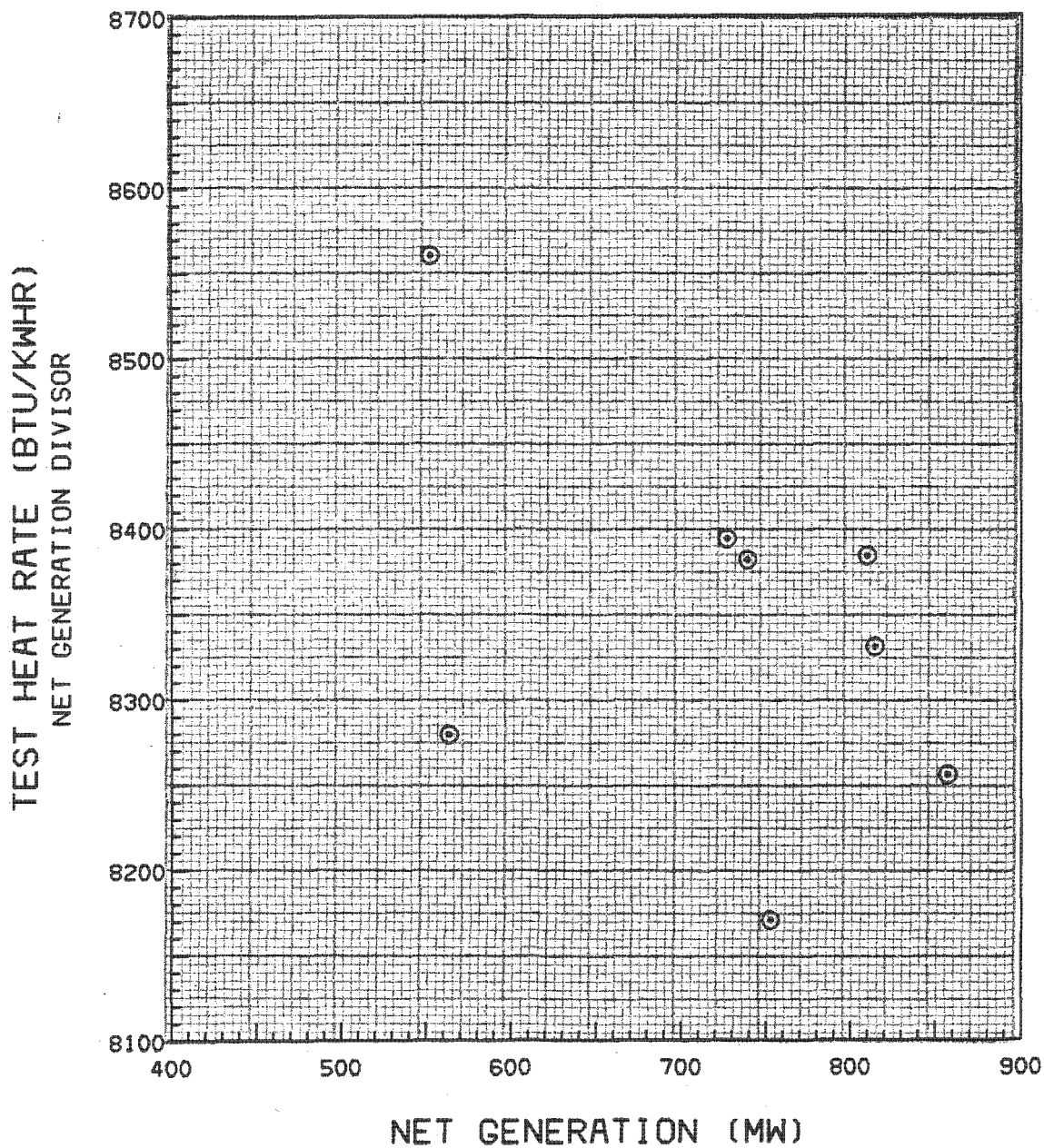


FIGURE 3-10: TEST HEAT RATE VS NET GENERATION  
INTERMOUNTAIN POWER AGENCY  
... IPP UNIT 2

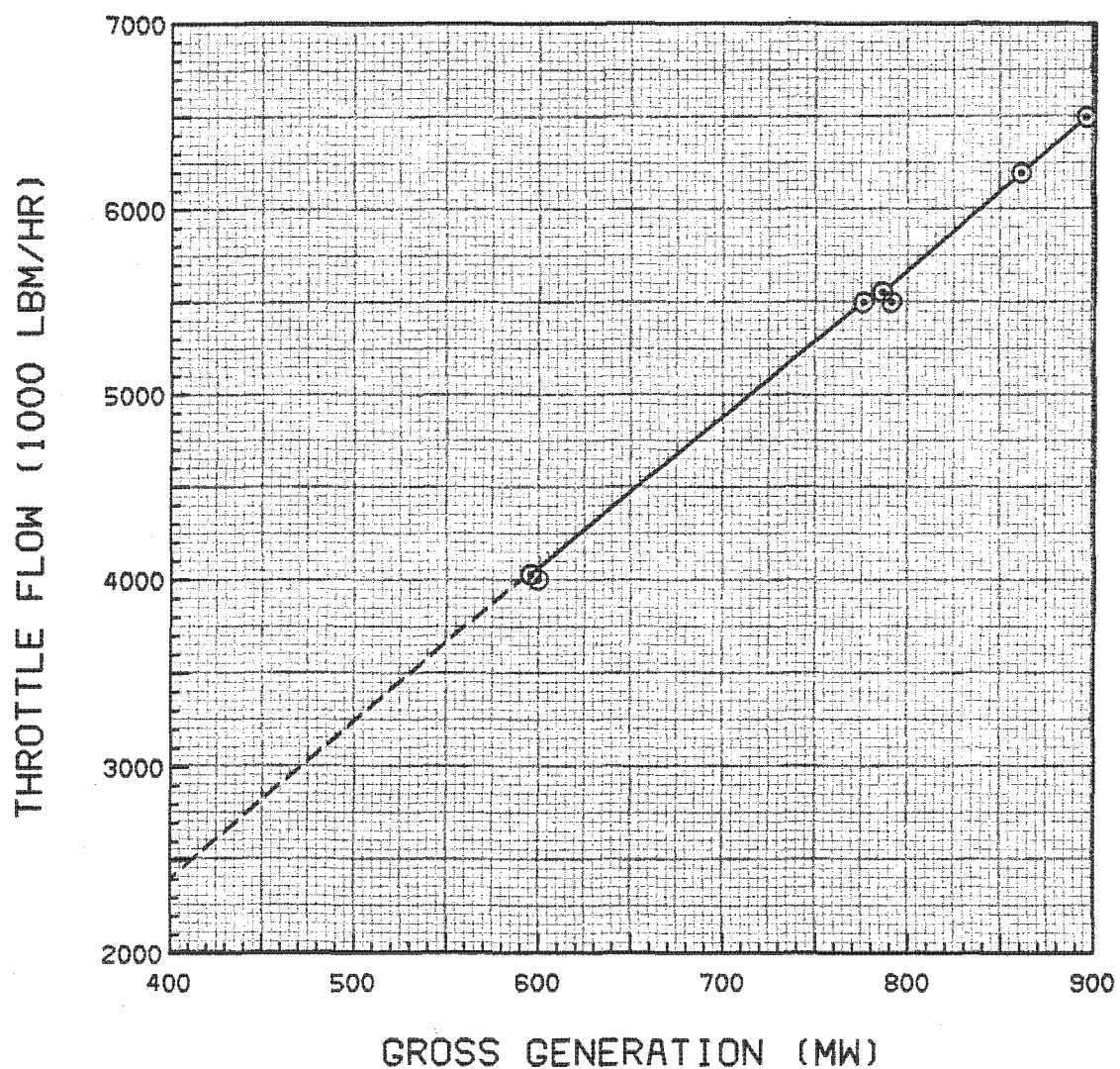


FIGURE 3-11: THROTTLE FLOW VS GROSS GENERATION  
INTERMOUNTAIN POWER AGENCY  
IPP UNIT 2

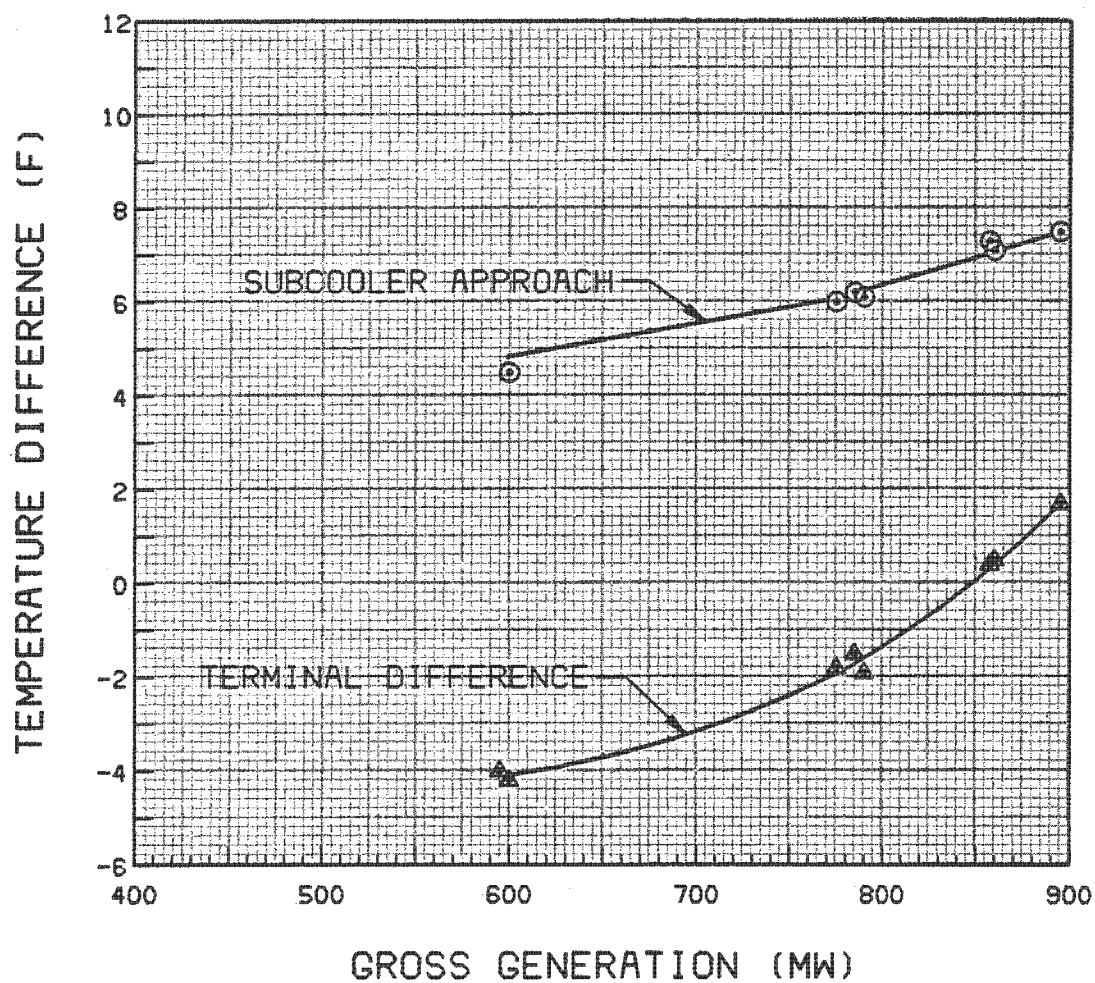


FIGURE 3-12: HEATER 8A PERFORMANCE  
INTERMOUNTAIN POWER AGENCY  
IPP UNIT 2

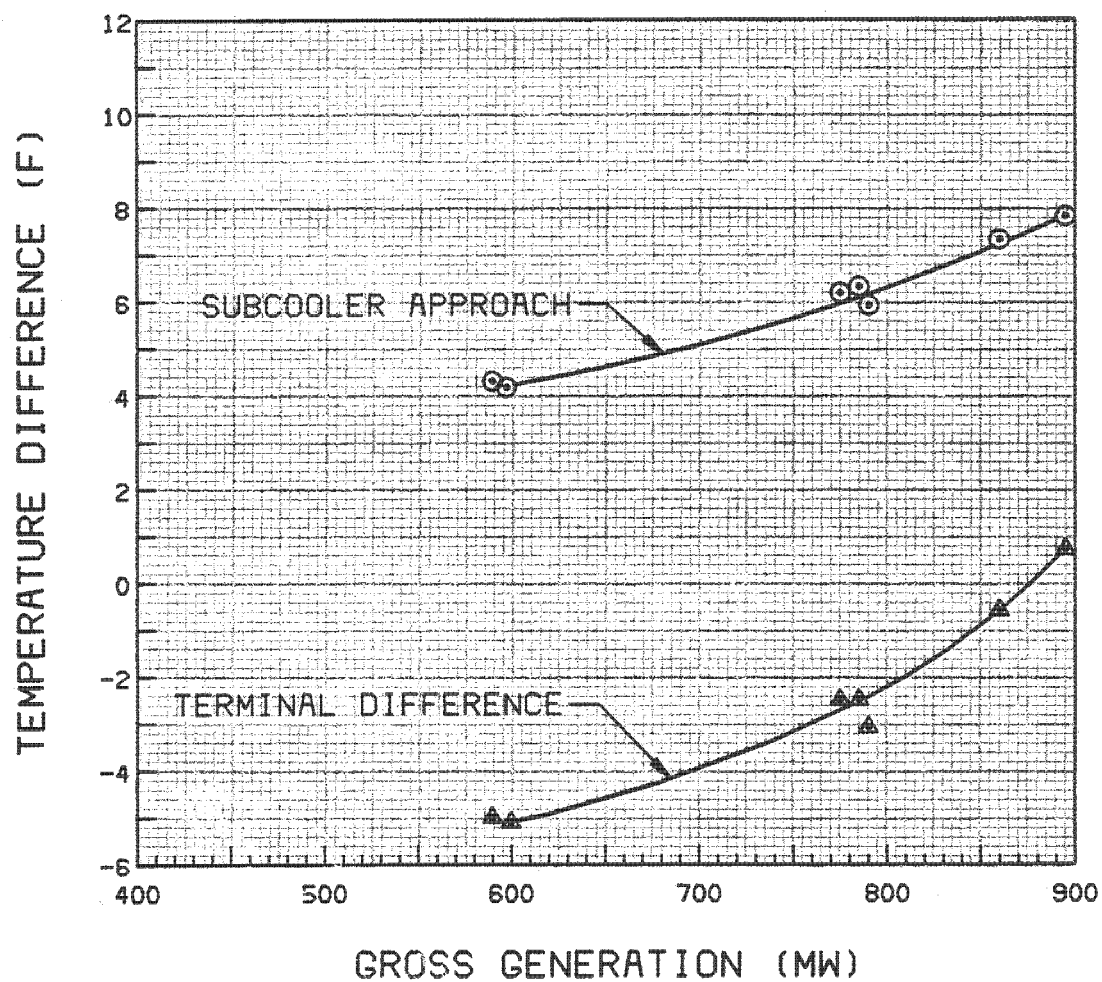


FIGURE 3-13: HEATER 8B PERFORMANCE  
INTERMOUNTAIN POWER AGENCY  
IPP UNIT 2

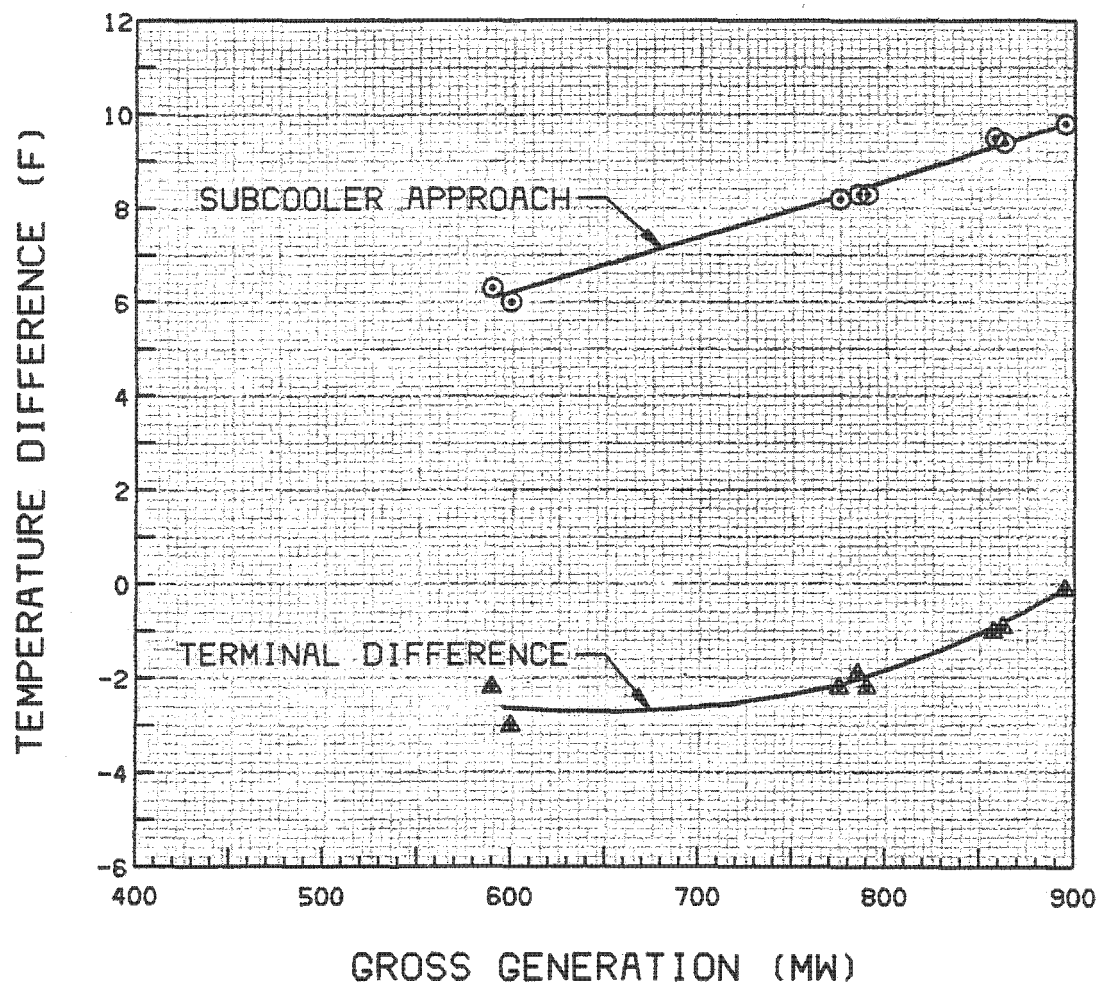


FIGURE 3-14: HEATER 7A PERFORMANCE  
INTERMOUNTAIN POWER AGENCY  
IPP UNIT 2

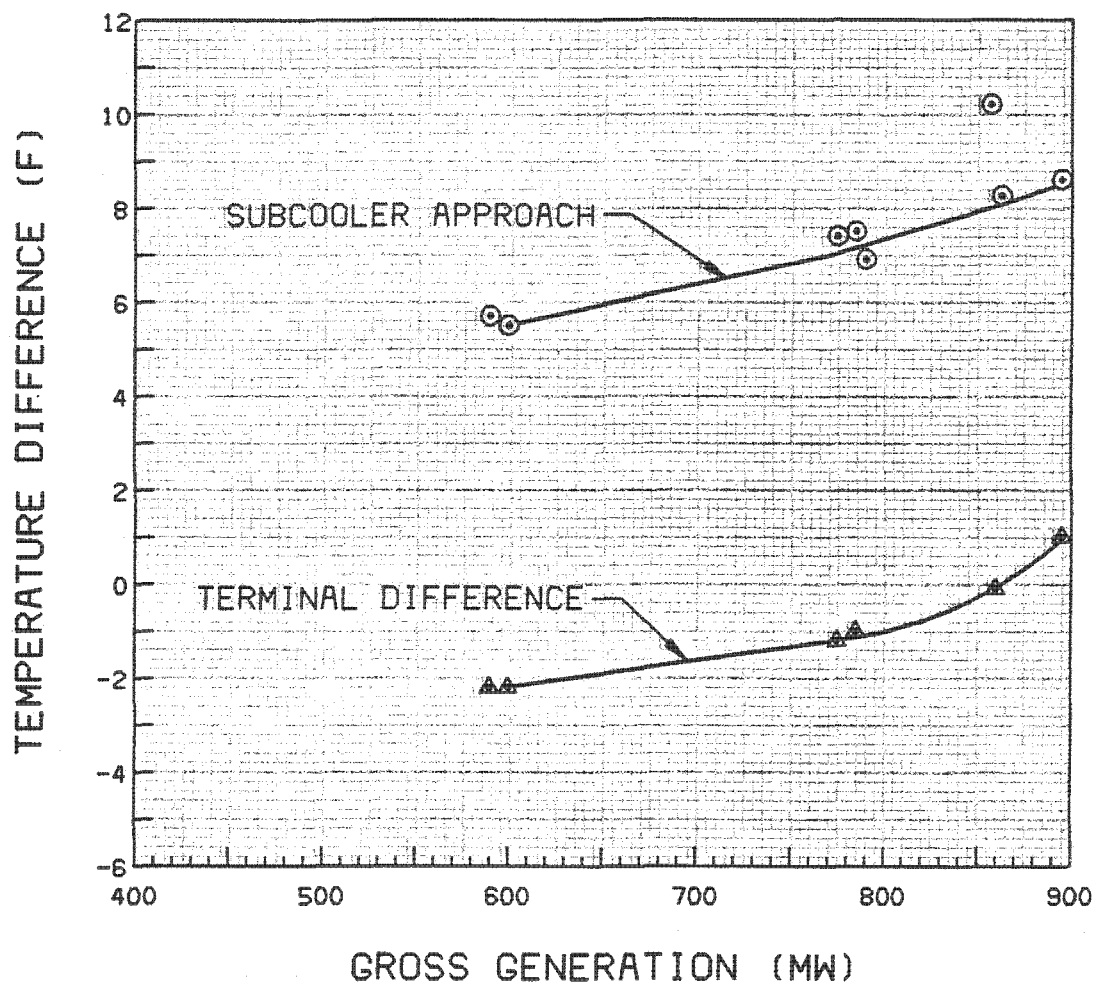


FIGURE 3-15: HEATER 7B PERFORMANCE  
INTERMOUNTAIN POWER AGENCY  
IPP UNIT 2

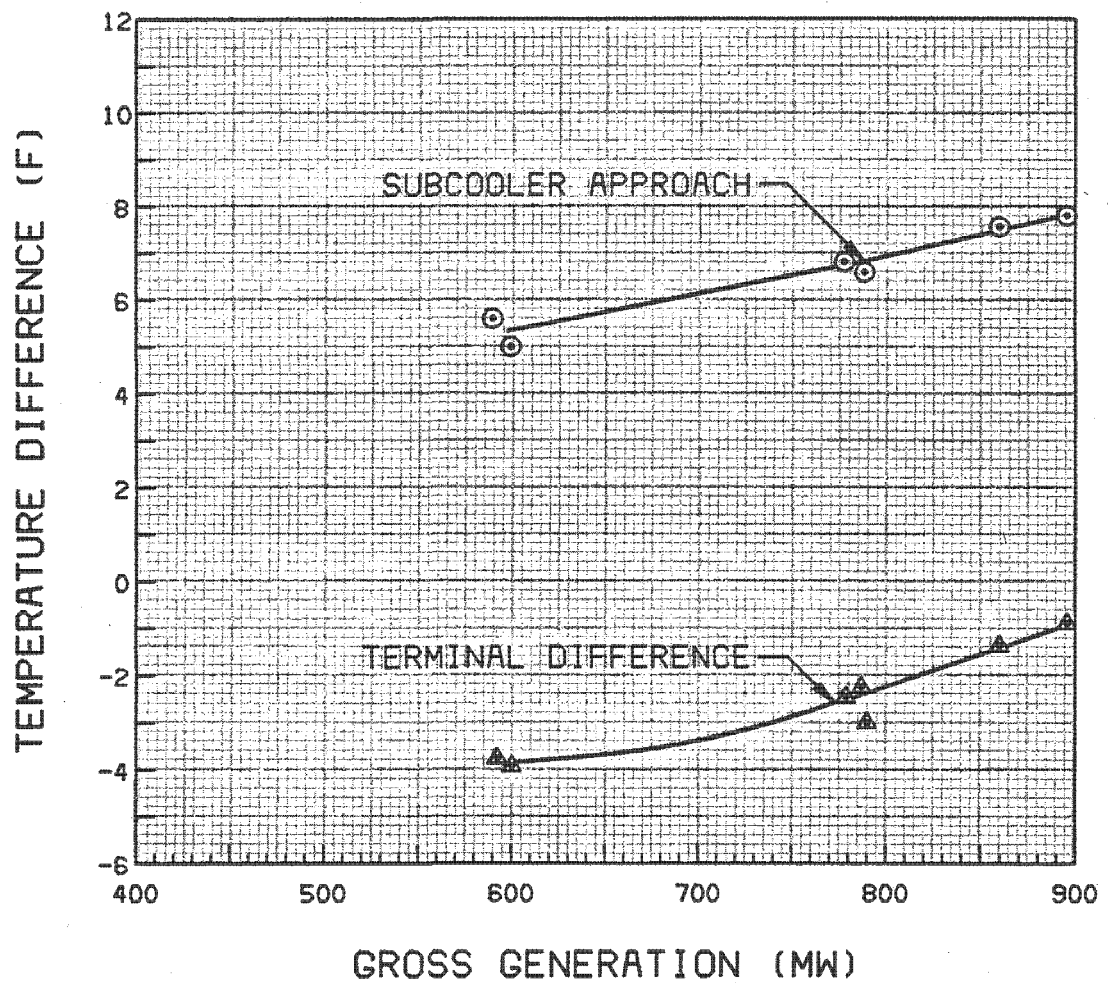


FIGURE 3-16: HEATER 6A PERFORMANCE  
INTERMOUNTAIN POWER AGENCY  
IPP UNIT 2



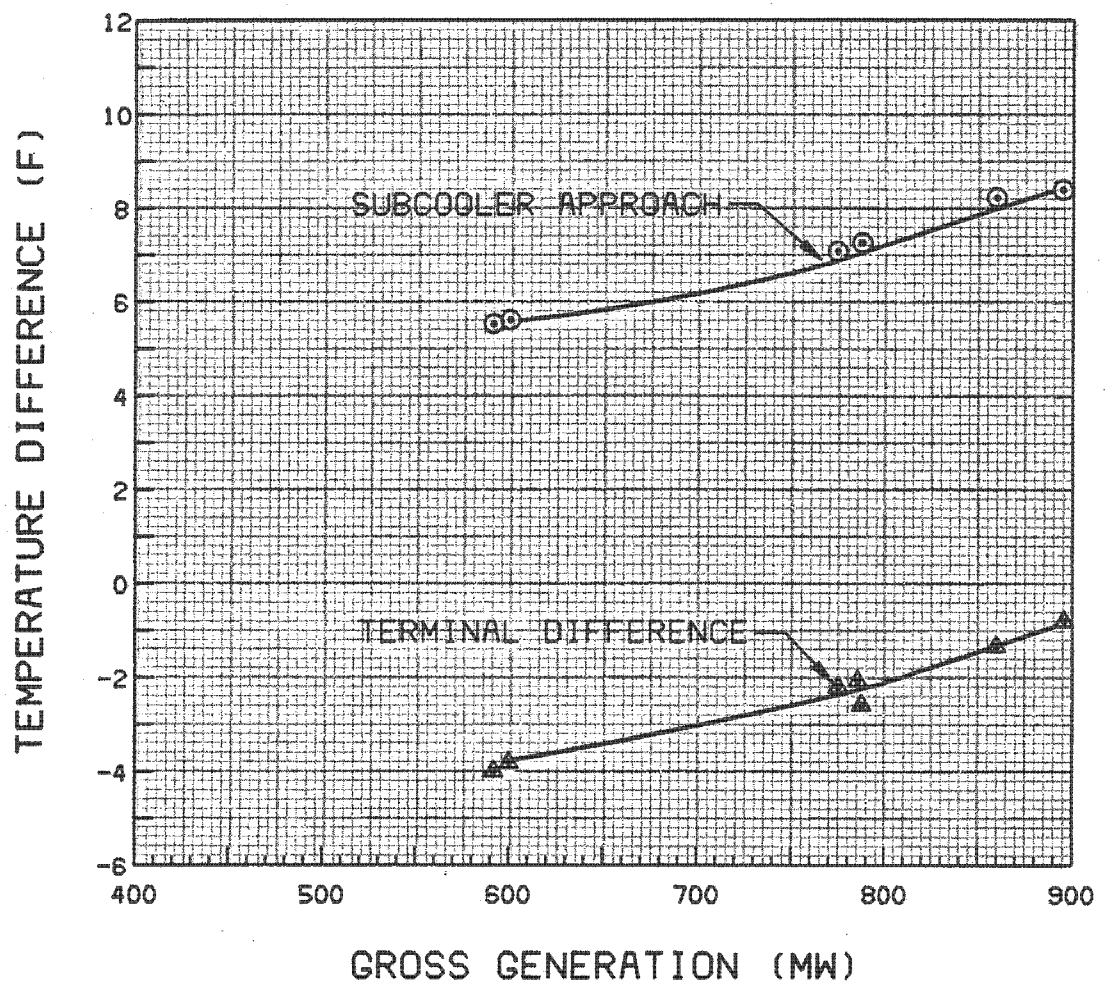


FIGURE 3-17: HEATER 6B PERFORMANCE  
INTERMOUNTAIN POWER AGENCY  
IPP UNIT 2



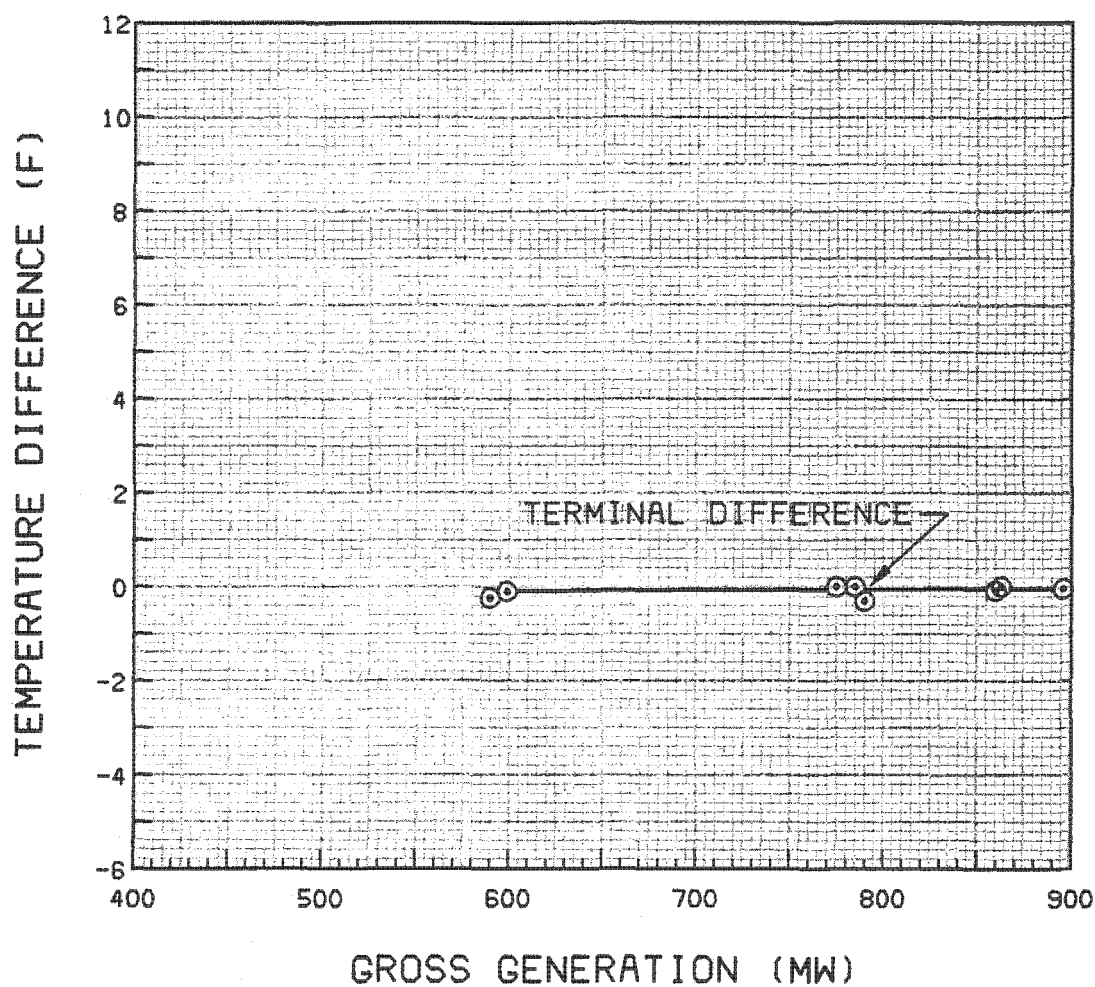


FIGURE 3-18: HEATER 5 PERFORMANCE  
INTERMOUNTAIN POWER AGENCY  
IPP UNIT 2

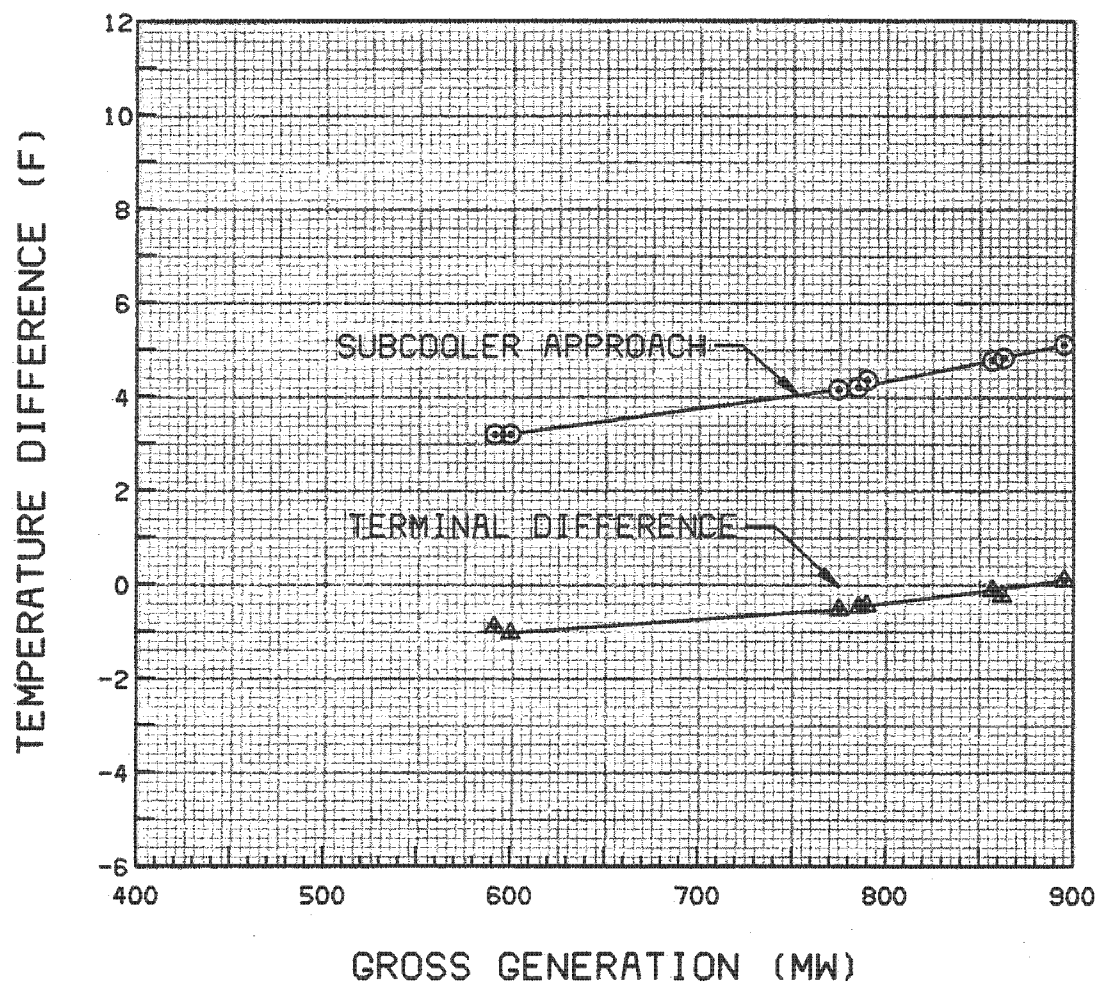


FIGURE 3-19: HEATER 4 PERFORMANCE  
INTERMOUNTAIN POWER AGENCY  
IPP UNIT 2

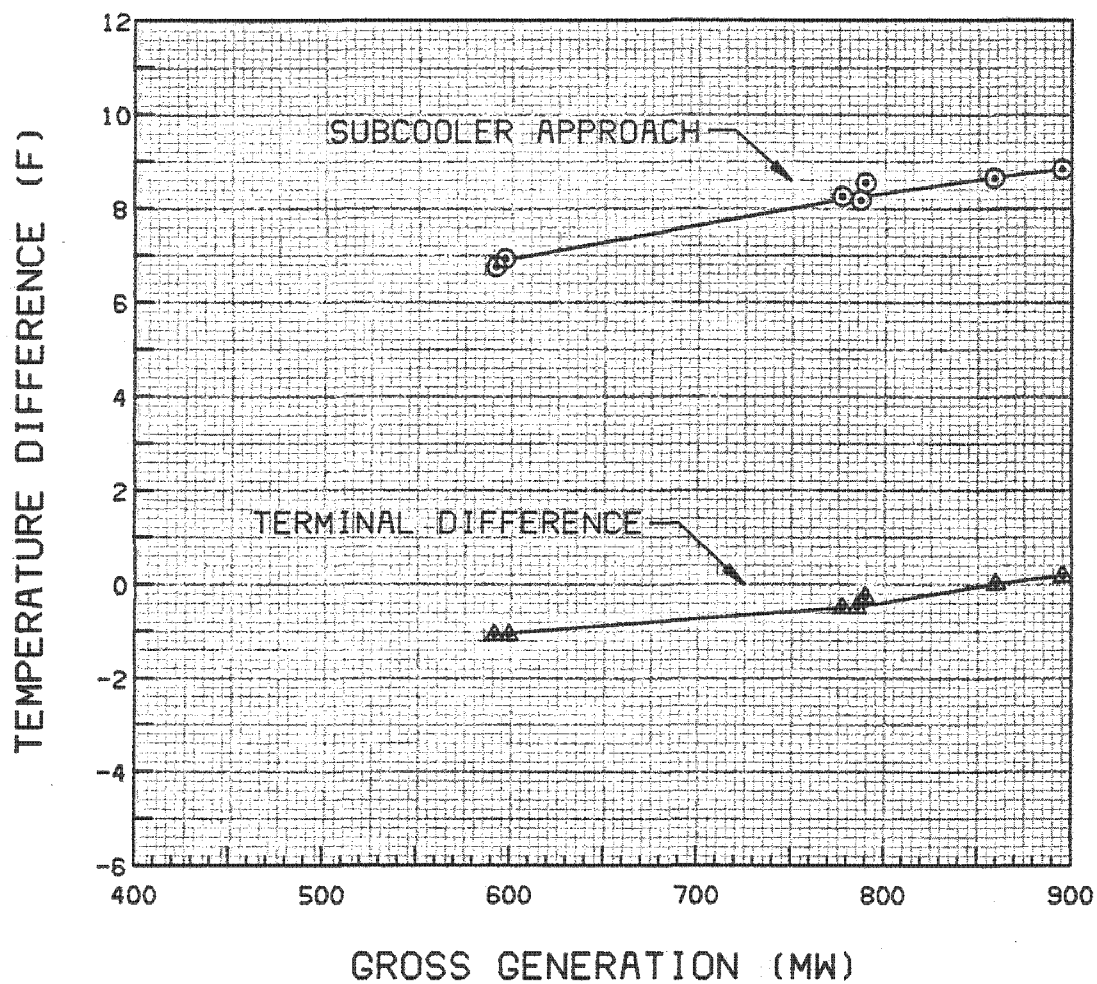


FIGURE 3-20: HEATER 3 PERFORMANCE  
INTERMOUNTAIN POWER AGENCY  
IPP UNIT 2

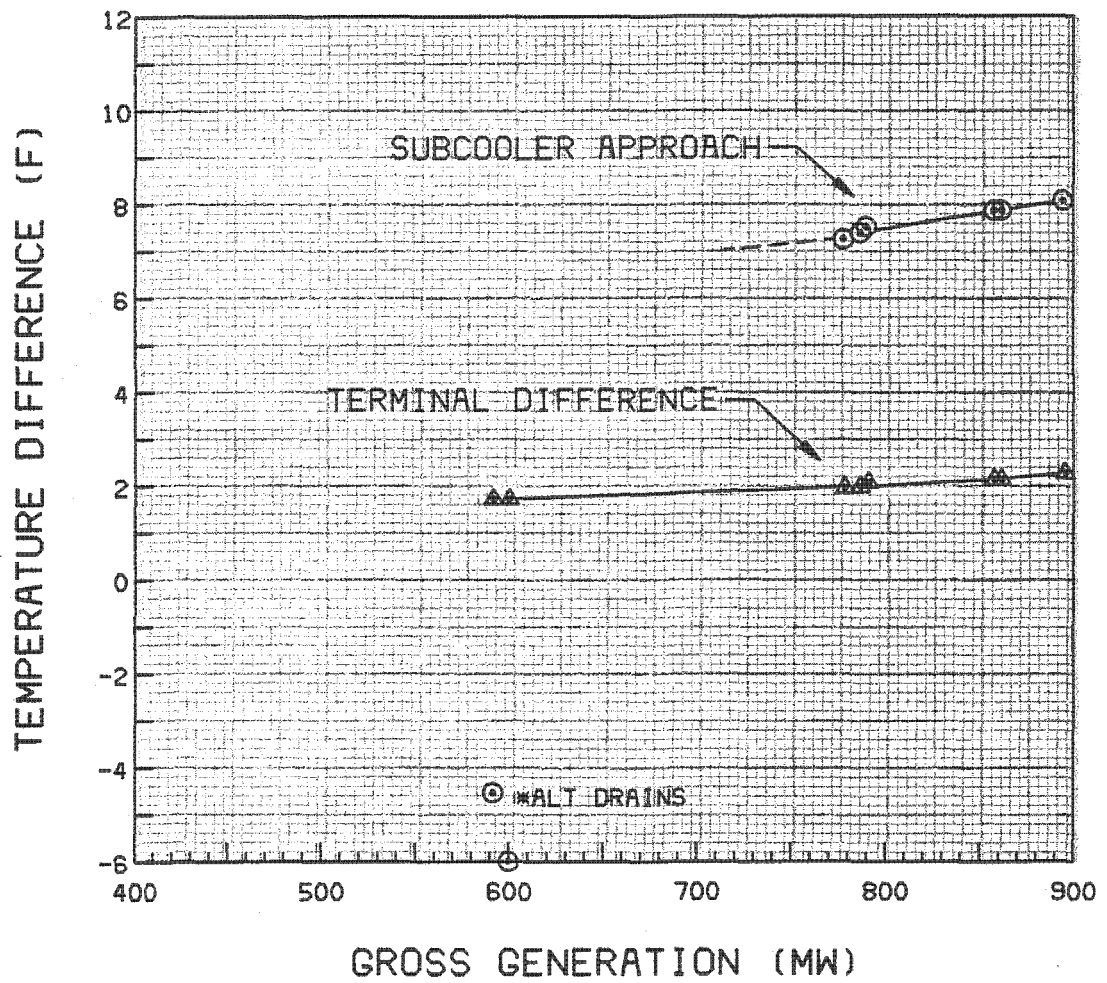


FIGURE 3-21: HEATER 2 PERFORMANCE  
INTERMOUNTAIN POWER AGENCY  
IPP UNIT 2

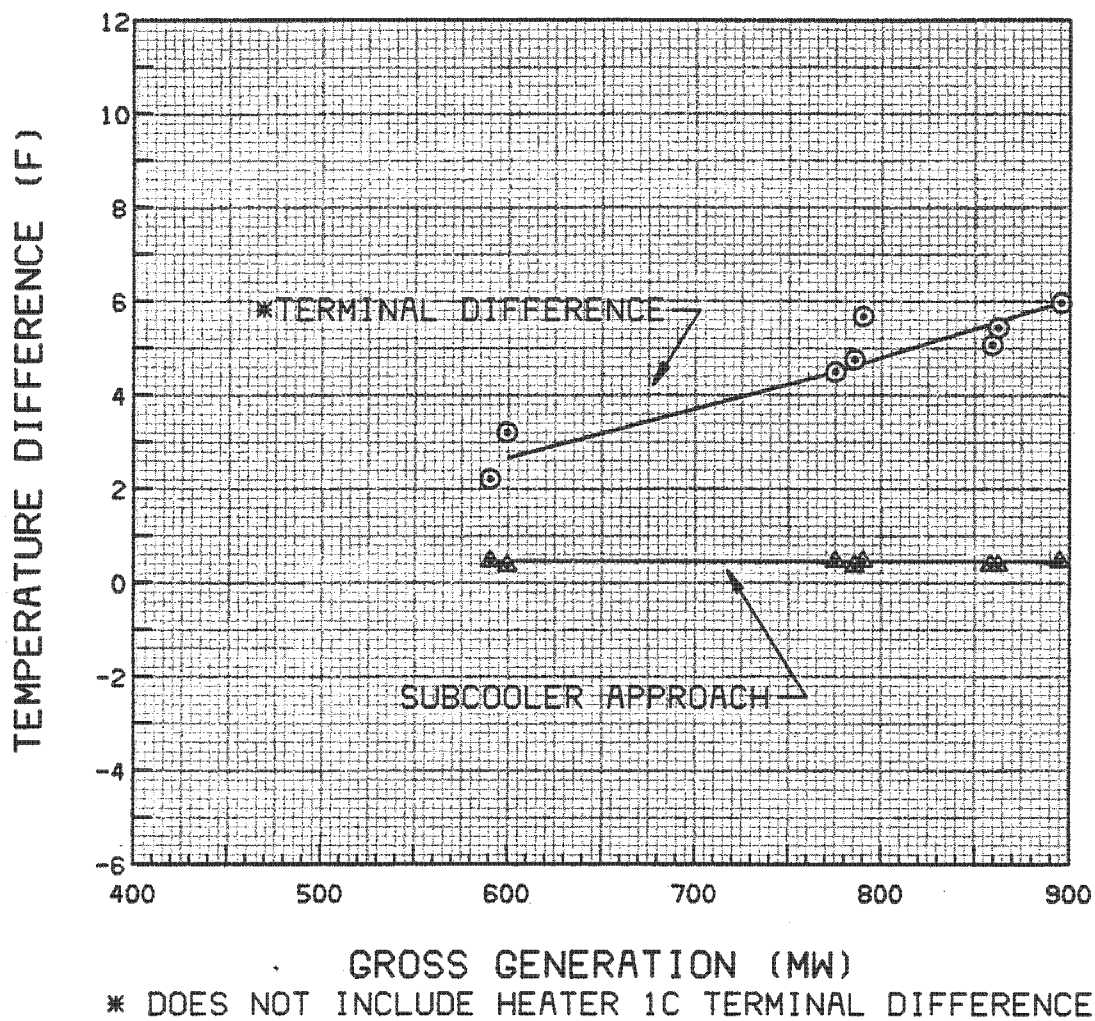


FIGURE 3-22: HEATER 1 PERFORMANCE  
INTERMOUNTAIN POWER AGENCY  
IPP UNIT 2

#### 4.0 PROCEDURE

The performance test was conducted to determine net plant heat rate, and the performance and efficiencies of the major equipment in the cycle. Data collected also establishes bench mark data for the unit.

Preliminary tests were conducted to check operation and readings of all instruments directly related to the test. This also allowed determination of cycle leakages for isolation purposes.

Eight tests were conducted: two each at valves wide open and at second valve point, three at third valve point, and one at valves wide open 5 percent overpressure. Data was collected by General Electric test computer, the plant computer, and manually. Pressures, temperatures, important flow measurements, and generator output were carefully measured with highly accurate measuring instruments. Balance-of-plant measurements were taken by plant instruments or by hand. All instruments were to be calibrated before testing commenced.

Generally, the tests began one hour after the unit had stabilized and were two hours in duration. Blowdown and makeup were isolated for the tests. Combustion conditions, rate of fuel flow, rate of feedwater flow, drum level, excess air, and all controllable temperatures and pressures were maintained as constant as possible for the duration of each test.

Data for each test were analyzed as soon as practicable after each test for acceptance.

The steam feedwater cycle was isolated as much as practicable to prevent large leakages. The condenser level was monitored to determine losses. Valves closed in the cycle for isolation are listed on the following pages.

## VALVE ISOLATION LIST

### AUXILIARY STEAM SYSTEM P&I DIAGRAM 9PSA-M2008

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Makeup from Unit 1 Deaerator	9PSA-BV-16
N	Makeup from Unit 1 Deaerator	9PSA-BV-18
N	Makeup from Unit 1 Deaerator	9PSA-BV-20
N	Makeup from Unit 1 Deaerator	9PSA-BV-22

N - Non-critical

C - Critical

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AUXILIARY STEAM SYSTEM  
P&I DIAGRAM 2PSA-M2008

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Cold Reheat to Aux Steam Use Telltale Valves 36 and 37 to verify isolation.	2PSA-MBV-17
N	Cold Reheat to Aux Steam	2PSA-BV-15
N	Cold Reheat to Aux Steam	2PSA-BV-11
N	Cold Reheat to Aux Steam Use Telltale Valves 123 and 127 to verify isolation.	2PSA-BV-12
N	Cold Reheat to Aux Steam	2PSA-BV-13
N	Cold Reheat to Aux Steam Use Telltale Valves 123 and 127 to verify isolation.	2PSA-BV-14
N	Aux Steam to Deaerator	2PSA-BV-22
N	Aux Steam to Deaerator Use Vent Valve 118 to verify isolation.	2PSA-BV-21
N	Aux Steam to Deaerator Storage Tank Use Telltale Valve 134 to verify isolation.	2PSA-BV-133
N	Aux Steam to Deaerator Storage Tank	2PSA-BV-6
N	Aux Steam to BFPT	2PSA-BV-19
N	Aux Steam to BFPT Use Telltale Valves 39 and 40 to verify isolation.	2PSA-BV-18
N	Aux Steam to Turbine Seals	2PSA-BV-26
N	CNDS to Aux Steam Desuperheater	2PSA-BV-7
N	CNDS to Aux Steam Desuperheater	2PSA-BV-8
N	CNDS to Aux Steam Desuperheater	2PSA-BV-9
N	Cold Reheat to Aux Steam Telltale	2PSA-BV-37
N	Main Deaerator Preheating Steam Vent	2PSA-BV-118

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AUXILIARY STEAM SYSTEM (Continued)  
P&I DIAGRAM 2PSA-M2008

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Deaerator Storage Tank Condensate Deaeration Steam Telltale	2PSA-BV-134
N	BFPT Startup Steam Telltale	2PSA-BV-40
N	Cold Reheat to Aux Steam Telltale	2PSA-BV-36
N	Steam From Secondary Superheater	2PSA-BV-58
N	Steam Trap No. 5	2PSA-BV-82
N	Steam Trap No. 5	2PSA-BV-83

N - Non-critical

C - Critical

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COMBUSTION GAS REHEAT SYSTEM  
P&I DIAGRAM 2CCD-M2013A

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Deaerator to Combustion Gas Reheat Use telltale valve to verify isolation.	2CCD-BV-150
N	Deaerator to Combustion Gas Reheat	2CCD-BV-435
N	Steam From Secondary Superheater Platen Outlet Header	2CCD-BV-44
N	Steam From Secondary Superheater Platen Outlet Header	2CCD-BV-47
N	Normal Return to Condensate Header Downstream of Heater 2 Telltale	2CCD-BV-436
N	Combustion Gas Reheat Pumps Recirculation	2CCD-BV-110
N	Combustion Gas Reheat Pumps Recirculation	2CCD-BV-113
N	Combustion Gas Reheat Pumps Recirculation	2CCD-BV-114
N	Combustion Gas Reheat Pumps Recirculation	2CCD-BV-117
N	AQCS RH Soot Blower Condensate Return	2CCD-BV-125
N	AQCS RH Soot Blower Condensate Return	2CCD-BV-127
N	Attemperator Spray From BFP Discharge	2CCD-BV-137
N	Attemperator Spray From BFP Discharge	2CCD-BV-139
N	Attemperator Spray From BFP Discharge	2CCD-BV-142

NOTE: Use Temperature Elements 903, 904, and 905 to verify system isolation.

N - Non-critical

C - Critical

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CONDENSING SYSTEM  
P&I DIAGRAM 2HRA-M2020

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
C	Condensate Makeup	2HRA-BV-30
C	Condensate Makeup	2HRA-BV-31
C	Condensate Makeup	2HRA-ACV-32
N	Condensate Makeup	2HRA-BV-33
N	Condensate Makeup	2HRA-BV-34
C	Condensate Drawoff	2HRA-BV-19
C	Condensate Drawoff	2HRA-BV-20
N	Condensate Drawoff	2HRA-BV-23
N	Condensate Drawoff	2HRA-BV-24
N	Condensate Pump Seals	2HRA-BV-71
	Use Telltale Valve 178 to verify isolation.	
N	Condensate Pump Seals	2HRA-BV-179
N	Condensate Pump Recirc	2HRA-ACV-25
N	Condensate Pump Recirc	2HRA-BV-29
N	Condensate Normal Makeup Drain	2HRA-BV-148
N	Condensate Emergency Makeup Telltale	2HRA-BV-175
N	Condensate Normal Drawoff Telltale	2HRA-BV-176
N	Condensate Emergency Drawoff Telltale	2HRA-BV-177
N	Condensate Misc Service Pumps Telltale	2HRA-BV-178
N	Hot Well Drain	2HRA-BV-89
N	Hot Well Drain	2HRA-BV-90
N	Hot Well Drain	2HRA-BV-91
N	Hydrazine Feed	2HRA-BV-92
N	Condenser Leak Detection Sample	2HRA-BV-112
N	Condenser Leak Detection Sample	2HRA-BV-113
N	Condenser Leak Detection Sample	2HRA-BV-114
N	Condenser Leak Detection Sample	2HRA-BV-115
N	Condenser Leak Detection Sample	2HRA-BV-116
N	Condenser Leak Detection Sample	2HRA-BV-117

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CONDENSING SYSTEM (Continued)  
P&I DIAGRAM 2HRA-M2020

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Condenser Leak Detection Sample	2HRA-BV-118
N	Condenser Leak Detection Sample	2HRA-BV-119

N - Non-critical

C - Critical

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CONDENSER AIR EXTRACTION  
P&I DIAGRAM 2HRB-M2021

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
C	Separator Makeup	2HRB-BV-109
C	Separator Makeup	2HRB-BV-110
C	Separator Makeup	2HRB-BV-111
C	Separator Makeup	2HRB-BV-112

N - Non-critical

C - Critical

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BOILER FEED SYSTEM  
P&I DIAGRAM 2FWA-M2035A

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
C	BFP Recirculation	2FWA-ACV-14
C	BFP Recirculation	2FWA-ACV-15
C	BFP Recirculation	2FWA-ACV-16
C	BFP Recirculation	2FWA-ACV-17
C	BFP Recirculation	2FWA-ACV-18
C	BFP Recirculation	2FWA-ACV-19
C	BFP Recirculation	2FWA-BV-37
N	Boot Strap Startup	2FWA-BV-298
	Use Telltale Valve 108 to verify isolation.	
N	Boot Strap Startup	2FWA-BV-299
N	Warmup Drain to Condenser	2FWA-BV-188
	Use Telltale Valve 365 to verify isolation.	
N	Warmup Drain to Condenser	2FWA-MBV-189
N	Boot Strap Startup Line Telltale	2FWA-BV-108
N	Warmup Drain to Condenser Telltale	2FWA-BV-365
N	Warmup Drain to Condenser Telltale	2FWA-BV-107

NOTE: All drains and vents to floor drains or atmosphere should be checked for leakage.

N - Non-critical

C - Critical

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BOILER FEED SYSTEM  
P&I DIAGRAM 2FWA-M2035B

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
C	Feedwater Heater Bypass	2FWA-MBV-44
N	Economizer Inlet Header Drain	2SGA-BV-131
N	Economizer Inlet Header Drain	2SGA-BV-132
C	Sample No. 11	2FWA-BV-202
C	Sample No. 11	2FWA-BV-203

N - Non-critical

C - Critical

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DRAINS AND VENTS  
P&I DIAGRAM 2FWA-M2035C

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	BFPT Drains	2FWA-ABV-303
N	BFPT Drains	2FWA-ABV-304
N	BFPT Drains	2FWA-ABV-305
N	BFPT Drains	2FWA-ABV-306
N	BFPT Drains	2FWA-ABV-307
N	BFPT Drains	2FWA-ABV-308
N	BFPT Drains	2FWA-ABV-309
N	BFPT Drains	2FWA-ABV-310
N	BFPT Drains	2FWA-ABV-311
N	BFPT Drains	2FWA-ABV-312
C	BFPT Drains	2FWA-BV-388
C	BFPT Drains	2FWA-BV-389
C	BFPT Drains	2FWA-BV-390
C	BFPT Drains	2FWA-BV-391
C	BFPT Drains	2FWA-BV-393

N - Non-critical

C - Critical

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CONDENSATE SYSTEM  
P&I DIAGRAM 2FWC-M2037

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Feedwater Heater Bypasses	2FWC-MBV-9
N	Feedwater Heater Bypasses	2FWC-MBV-16
N	Feedwater Heater Bypasses	2FWC-MBV-17
N	Feedwater Heater Bypasses	2FWC-MBV-18
N	Deaerator Drain to Condenser	2FWC-BV-85
	Use Telltale Valve 110 to verify isolation.	
N	Deaerator Drain to Condenser	2FWC-BV-86
C	Deaerator Drain to Condenser	2FWC-BV-26
	Use Telltale Valve 105 to verify isolation.	
C	Deaerator Drain to Condenser	2FWC-BV-27
N	Deaerator Drain to Gen Bldg Drain	2FWC-BV-23
N	Air Preheat Supply	2FWC-BV-24
C	Recirculation to Condenser	2FWC-MBV-90
N	Recirculation to Condenser Telltale	2FWC-BV-110
N	Recirculation to Condenser Drain	2FWC-BV-105

N - Non-critical

C - Critical

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CONDENSATE POLISHING SYSTEM  
P&I DIAGRAMS 2FWD-M2038A AND M2038B

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
	Do not regenerate polishers during test.	
C	Makeup to Regen Pumps	2FWD-BV-121
C	Makeup to Regen Pumps	2FWD-BV-125
N	Demineralizer Resin Transfer	2FWD-MBV-72
N	Demineralizer Resin Transfer	2FWD-MBV-73
N	Demineralizer Resin Transfer	2FWD-MBV-74
N	Demineralizer Resin Transfer	2FWD-MBV-75
N	Condensate Demineralizer Drain	2FWD-MBV-76
N	Condensate Demineralizer Drain	2FWD-MBV-77
N	Condensate Demineralizer Drain	2FWD-MBV-78
N	Condensate Demineralizer Drain	2FWD-MBV-79

N - Non-critical

C - Critical

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4-13

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CYCLE MAKEUP AND STORAGE  
P&I DIAGRAM 2FWF-M2040

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Low-Pressure Heater Drains	2FWF-BV-66

N - Non-critical

C - Critical

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STEAM CYCLE SAMPLING AND ANALYSIS  
P&I DIAGRAM 2SAC-M2054A

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Sample No. 1	2SAC-BV-17
N	Sample No. 1	2SAC-BV-5
N	Sample No. 1	2SAC-BV-30
N	Sample No. 2	2SAC-BV-6
N	Sample No. 3	2SAC-BV-19
N	Sample No. 3	2SAC-BV-7
N	Sample No. 3	2SAC-BV-32
N	Sample No. 4	2SAC-BV-20
N	Sample No. 4	2SAC-BV-8
N	Sample No. 4	2SAC-BV-33
N	Sample No. 5	2SAC-BV-21
N	Sample No. 5	2SAC-BV-9
N	Sample No. 5	2SAC-BV-34
N	Sample No. 6	2SAC-BV-22
N	Sample No. 6	2SAC-BV-10
N	Sample No. 6	2SAC-BV-35
N	Sample No. 7	2SAC-BV-23
N	Sample No. 7	2SAC-BV-11
N	Sample No. 7	2SAC-BV-36
N	Sample No. 8	2SAC-BV-1
N	Sample No. 8	2SAC-BV-12
N	Sample No. 8	2SAC-BV-24
N	Sample No. 8	2SAC-BV-37
N	Sample No. 9	2SAC-BV-2
N	Sample No. 10	2SAC-BV-13
N	Sample No. 11	2SAC-BV-26
N	Sample No. 11	2SAC-BV-14
N	Sample No. 11	2SAC-BV-39
N	Sample No. 12	2SAC-BV-15
N	Sample No. 13	2SAC-BV-3

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STEAM CYCLE SAMPLING AND ANALYSIS (Continued)  
P&I DIAGRAM 2SAC-M2054A

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Sample No. 14	2SAC-BV-4
N	Sample No. 14	2SAC-BV-16
N	Sample No. 14	2SAC-BV-26
N	Sample No. 14	2SAC-BV-41
N	Sample Recovery Pump Suction	2SAC-BV-107
N	Sample Recovery Pump Discharge	2SAC-BV-110

N - Non-critical

C - Critical

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4-16

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GENERATION BUILDING SPACE CONDITIONING  
P&I DIAGRAM 2SCA-M2056A

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Space Conditioning Drain	2SGA-BV-429

N - Non-critical

C - Critical

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4-17

IP14\_000857

STEAM GENERATOR SYSTEM  
P&I DIAGRAM 2SGA-M2063A

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Superheat Bypass to Condenser Use Telltale Valves 165 and 166 to verify isolation.	2SGA-BV-136
N	Superheat Bypass to Condenser	2SGA-BV-138
N	Superheat Bypass to Condenser Use Telltale Valves 121 and 218 to verify isolation.	2SGA-BV-169
N	Superheat Bypass to Condenser	2SGA-BV-170
N	Superheat Bypass to Reheat	2SGA-MBV-135
N	Superheat Bypass to Reheat	2SGA-BV-125
N	Superheat Bypass to Reheat	2SGA-ACV-134
N	Superheat Bypass to Reheat	2SGA-MUV-133
N	Boiler Soot Blowing Steam Supply	2SGA-BV-141
C	Boiler Soot Blowing Steam Supply	2SGA-MBV-142
N	AH Soot Blowing Steam Supply	2SGA-BV-139
C	AH Soot Blowing Steam Supply	2SGA-MBV-140
N	Boiler Soot Blowing Steam Supply	2SGA-BV-143
C	Boiler Soot Blowing Steam Supply	2SGA-MBV-144
N	Combustion Gas Reheater Soot Blowing Steam Supply Use Temperature Indicator 1CCD-TI-120 to verify isolation.	2SGA-BV-17
N	Combustion Gas Reheater Soot Blowing Steam Supply	2SGA-MBV-24
N	Steam Supply to Aux Steam Header	2SGA-BV-10
N	Steam Trap No. 2	2SGA-BV-195
N	Steam Supply to Aux Steam Header Use Telltale Valves 203 and 204 to verify isolation.	2SGA-MBV-194
N	Secondary Superheater Outlet Header	2SGI-BV-1
N	Secondary Superheater Outlet Header	2SGI-BV-2

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STEAM GENERATOR SYSTEM (Continued)  
P&I DIAGRAM 2SGA-M2063A

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Secondary Superheater Platen Outlet Header	2SGI-ACV-29
N	Secondary Superheater Platen Outlet Header	2SGI-ACV-30

N - Non-critical

C - Critical

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STEAM GENERATOR SYSTEM  
P&I DIAGRAM 2SGA-M2063B

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Gauge Glass LG-1 Drain	2SGA-BV-11
N	Gauge Glass LG-1 Drain	2SGA-BV-12
N	Gauge Glass LG-1 Drain	2SGA-BV-207
N	Gauge Glass LG-3 Drain	2SGA-BV-25
N	Gauge Glass LG-3 Drain	2SGA-BV-26
N	Gauge Glass LG-2 Drain	2SGA-BV-18
N	Gauge Glass LG-2 Drain	2SGA-BV-208
N	Gauge Glass LG-2 Drain	2SGA-BV-19
N	Future Sample	2SGA-BV-54
N	Drain to Blowdown Header	2SGA-BV-31
N	Drain to Blowdown Header	2SGA-BV-32
C	Continuous Blowdown	2SGA-MBV-4
C	Continuous Blowdown	2SGA-BV-3
N	To Auxiliary Steam Supply	2SGA-BV-1
N	To Auxiliary Steam Supply	2SGA-MBV-2
	Use Telltale Valves 206 and 205 to verify isolation.	
N	Steam Supply to Aux Steam Header Trap No. 3	2SGA-BV-199
C	Sample No. 13	2SGA-BV-172

N - Non-critical

C - Critical

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AIR PREHEAT SYSTEM  
P&I DIAGRAM 2SGC-M2065

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Air Preheat Pumps Bypass	2SGC-BV-119
N	Air Preheat Pumps Inlet	2SGC-BV-113
N	Air Preheat Pumps Inlet	2SGC-BV-114
N	Air Preheat Return to Condenser	2SGC-BV-122
N	Air Preheat Recirculation	2SGC-BV-123
N	Air Preheat Return to Deaerator	2SGC-BV-140
N	Air Preheat Return to Deaerator Teiltale	2SGC-BV-148
N	Air Preheat Return to Condenser	2SGC-BV-141
N	Air Preheat Return to Condenser Teiltale	2SGC-BV-149
N	Air Preheat Emergency Return to Condenser	2SGC-BV-137
N	Air Preheat Emergency Return to Condenser	2SGC-BV-139
N	Air Preheat Emergency Return to Condenser Drain	2SGC-BV-166
N	Air Preheat Emergency Return to Condenser	2SGC-BV-130
N	Air Preheat Emergency Return to Condenser	2SGC-BV-131

N - Non-critical

C - Critical

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BOILER VENTS AND DRAINS SYSTEM  
P&I DIAGRAM 2SGF-M2068

DRAINS

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Lwr Convection Pass Header	2SGF-BV-28
N	Lwr Convection Pass Header	2SGF-MBV-29
N	Economizer Inlet Header	2SGF-BV-30
N	Economizer Inlet Header	2SGF-BV-31
N	Reheater Inlet Header	2SGF-BV-33
N	Reheater Inlet Header	2SGF-BV-34
N	Lwr Convection Pass Header	2SGF-BV-35
N	Lwr Convection Pass Header	2SGF-MBV-36
N	Reheater Outlet Header	2SGF-BV-37
N	Reheater Outlet Header	2SGF-BV-38
N	Reheater Outlet Header	2SGF-BV-39
N	Reheater Outlet Header	2SGF-BV-40
N	Secondary Superheater Outlet Header	2SGF-BV-41
N	Secondary Superheater Outlet Header	2SGF-MBV-42
N	Secondary Superheater Inter Inlet Header	2SGF-BV-43
N	Secondary Superheater Inter Inlet Header	2SGF-MBV-44
N	Secondary Superheater Inter Inlet Header	2SGF-BV-45
N	Secondary Superheater Inter Inlet Header	2SGF-MBV-46
N	Drum Feed Header	2SGF-BV-47
N	Drum Feed Header	2SGF-BV-48
N	Secondary Superheater Platen Inlet Header	2SGF-BV-49
N	Secondary Superheater Platen Inlet Header	2SGF-MBV-50
N	Roof Inlet Header	2SGF-BV-51
N	Roof Inlet Header	2SGF-MBV-52
N	Drum Feed Header	2SGF-BV-53
N	Drum Feed Header	2SGF-BV-54
N	Lwr Convection Pass Header	2SGF-BV-55
N	Lwr Convection Pass Header	2SGF-MBV-56
N	Lwr Convection Pass Header	2SGF-BV-57

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**BOILER VENTS AND DRAINS SYSTEM (Continued)**  
**P&I DIAGRAM 2SGF-M2068**

**DRAINS**

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Lwr Convection Pass Header	2SGF-MBV-58
N	Drum West End	2SGF-BV-59
	Drum West End	2SGF-BV-60
N	Drum West End	2SGF-BV-61
N	Drum West End	2SGF-BV-62
N	Drum West End	2SGF-BV-63
N	Drum West End	2SGF-BV-64
N	Downcomer Drain Manifold	2SGF-BV-65
N	Downcomer Drain Manifold	2SGF-MBV-66
N	Drum East End	2SGF-BV-67
N	Drum East End	2SGF-BV-68
N	Drum East End	2SGF-BV-69
N	Drum East End	2SGF-BV-70

**VENTS**

N	Economizer Discharge Line	2SGF-BV-17
N	Primary Superheater Outlet Header	2SGF-MBV-19
N	Secondary Superheater Platen Outlet Header	2SGF-MBV-22
N	Drum West End	2SGF-MBV-10
N	Drum East End	2SGF-MBV-14
N	Primary Superheater Outlet Header	2SGF-MBV-24
N	Economizer Discharge Line	2SGF-BV-26

N - Non-critical

C - Critical

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MAIN STEAM SYSTEM  
P&I DIAGRAM 2SGG-M2069

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
C	Main Steam Vent to Atmosphere	2SGG-MBV-21
C	Fill Line For Superheater Hydro Test	2SGG-BV-61
C	Main Steam to BFPT 1A	2SGG-MBV-9
C	Main Steam to BFPT 1B	2SGG-MBV-10
	Use temperature measurements at TW-13 and TW-14 to verify isolation.	
N	Main Steam Warming Line	2SGG-MBV-17
N	Main Steam Warming Line	2SGG-MCV-18
N	Main Steam Drain to Blowdown Tank	2SGG-MBV-13
N	Main Steam Drain to Blowdown Tank	2SGG-MBV-14
N	Main Steam to BFPT 1A Bypass	2SGG-BV-23
N	Main Steam to BFPT 1B Bypass	2SGG-BV-24
N	Main Steam Drain to Condenser	2SGG-MBV-25
N	Main Steam Drain to Condenser	2SGG-MBV-26
N	BFPT Main Steam Drain to Blowdown Tank	2SGG-MBV-11
N	BFPT Main Steam Drain to Blowdown Tank	2SGG-MBV-12
N	BFPT Main Steam Drain to Condenser	2SGG-MBV-55
N	BFPT Main Steam Drain to Condenser	2SGG-MBV-56
N	Condensate to Desuperheater	2SGG-ACV-59
N	Main Steam Line Warming Desuperheater	2SGG-BV-58
N	Main Steam Line Warming Desuperheater	2SGG-MCV-18
N	Sample No. 14	2SGG-BV-15
N	Sample No. 14	2SGG-BV-16
N	Condensate to Warming Desuperheater	2SGG-BV-60

N - Non-critical

C - Critical

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SOOT BLOWING  
P&I DIAGRAM 2SGI-M2070

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Main Steam to Soot Blowers	2SGI-ACV-3
N	Main Steam to Soot Blowers	2SGI-ACV-4
N	Main Steam to Soot Blowers	2SGI-ACV-25
N	Main Steam to Soot Blowers	2SGI-ACV-26
N	Soot Blowers Steam to HP Heater Extraction	2SGI-MBV-35
N	Soot Blowers Steam to HP Heater Extraction	2SGI-MBV-178

N - Non-critical

C - Critical

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HOT/COLD REHEAT SYSTEM  
P&I DIAGRAM 2SGJ-M2071

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Hot Reheat Drains	2SGJ-MBV-16
N	Hot Reheat Drains	2SGJ-MBV-14
N	Cold Reheat Drains	2SGJ-MBV-18
N	Cold Reheat Drains	2SGJ-BV-56
N	Cold Reheat Drains	2SGJ-BV-57
N	Reheat Desuperheater Spray	2SGJ-ACV-58
N	Reheat Desuperheater Spray	2SGJ-ACV-59
N	Reheat Desuperheater Spray	2SGJ-ACV-66
N	Reheat Desuperheater Spray	2SGJ-ACV-67
N	CNDS to Cold Reheat Drain Desuperheater	2SGJ-BV-90

N - Non-critical

C - Critical

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HIGH-PRESSURE EXTRACTION SYSTEM  
P&I DIAGRAM 2TEA-M2073

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Aux Steam to BFPT	2TEA-MBV-118

N - Non-critical

C - Critical

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EXTRACTION TRAPS AND DRAINS SYSTEM  
P&I DIAGRAM 2TEC-M2075

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
C	HP Heaters 8A and 8B Extr Drain	2TEC-BV-73
C	HP Heaters 8A and 8B Extr Drain	2TEC-BV-75
C	HP Heater 8A Extr Drain	2TEC-BV-79
C	HP Heater 8A Extr Drain	2TEC-BV-81
C	HP Heater 6B Extr Drain	2TEC-BV-105
N	LP Heater 3 Extr Drain	2TEC-BV-35
N	HP Heaters 8A and 8B Extr Drain	2TEC-ACV-74
N	HP Heater 8A Extr Drain	2TEC-ACV-80
C	HP Heater 8B Extr Drain	2TEC-ACV-86
C	HP Heaters 6A and 6B Extr Drain	2TEC-ACV-92
C	HP Heater 6A Extr Drain	2TEC-ACV-98
C	HP Heater 6B Extr Drain	2TEC-ACV-104
C	BFPT 1B Extr Drain	2TEC-ACV-140
C	BFPT 1A Extr Drain	2TEC-ACV-134
C	Deaerator Heater 5 Extr Drain	2TEC-ACV-128
C	BFPT 1A and 1B Extr Drain	2TEC-ACV-122
C	Deaerator Heater 5 Extr Drain	2TEC-ACV-116
C	Deaerator Heater 5 Extr Drain	2TEC-ACV-110
C	BFPT 1A Extr Drain	2TEC-ACV-146
C	BFPT 1B Extr Drain	2TEC-ACV-152
C	LP Heater 4 Extr Drain	2TEC-BV-65
N	LP Heater 4 Extr Drain	2TEC-BV-67
N	Miscellaneous Drains Rcvr Tank	2TEC-BV-163
	Vent and overflow should be checked for leaks.	
N	LP Heater 2 Extr Drain	2TEC-ACV-2
N	LP Heater 2 Extr Drain	2TEC-ACV-6
N	LP Heater 3 Extr Drain	2TEC-ACV-10
N	LP Heater 3 Extr Drain	2TEC-ACV-14
N	LP Heater 4 Extr Drain	2TEC-ACV-18
N	LP Heater 4 Extr Drain	2TEC-ACV-22
N	LP Heater 2 Extr Drain	2TEC-ACV-50

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EXTRACTION TRAPS AND DRAINS SYSTEM (Continued)  
P&I DIAGRAM 2TEC-M2075

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	LP Heater 2 Extr Drain	2TEC-ACV-54
N	LP Heater 3 Extr Drain	2TEC-ACV-58
N	LP Heater 3 Extr Drain	2TEC-ACV-62
N	LP Heater 4 Extr Drain	2TEC-ACV-66
N	LP Heater 4 Extr Drain	2TEC-ACV-70
N	LP Heater 2 Extr Drain	2TEC-ACV-26
N	LP Heater 2 Extr Drain	2TEC-ACV-30
N	LP Heater 3 Extr Drain	2TEC-ACV-34
N	LP Heater 3 Extr Drain	2TEC-ACV-38
N	LP Heater 4 Extr Drain	2TEC-ACV-42
N	LP Heater 4 Extr Drain	2TEC-ACV-46
N	LP Heater 4 Extr Drain	2TEC-BV-39
N	LP Heater 4 Extr Drain	2TEC-BV-43
N	LP Heater 4 Extr Drain	2TEC-BV-47
C	LP Heater 3 Extr Drain	2TEC-BV-11
N	LP Heater 3 Extr Drain	2TEC-BV-15
C	LP Heater 4 Extr Drain	2TEC-BV-19
N	LP Heater 4 Extr Drain	2TEC-BV-23
N	LP Heater 3 Extr Drain	2TEC-BV-59
N	LP Heater 3 Extr Drain	2TEC-BV-63
N	LP Heater 2 Extr Drain	2TEC-BV-27
N	LP Heater 2 Extr Drain	2TEC-BV-31
N	LP Heater 2 Extr Drain	2TEC-BV-3
N	LP Heater 2 Extr Drain	2TEC-BV-7
N	LP Heater 2 Extr Drain	2TEC-BV-51
N	LP Heater 2 Extr Drain	2TEC-BV-55

NOTE: Isolation of the extraction drains should be verified by checking the surface temperature of the drain pipe.

N - Non-critical

C - Critical

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HIGH-PRESSURE HEATER DRAINS  
P&I DIAGRAM 2TED-M2076

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	HP Heater Drain Return	2TED-ACV-13
N	HP Heater Drain Return	2TED-ACV-14
C	HP Heater Drain to Condenser	2TED-BV-19
C	HP Heater Drain to Condenser	2TED-BV-20
C	HP Heater Drain to Condenser	2TED-BV-21
C	HP Heater Drain to Condenser	2TED-BV-22
C	HP Heater Drain to Condenser	2TED-BV-27
C	HP Heater Drain to Condenser	2TED-BV-28
C	HP Heater Drain to Condenser	2TED-BV-29
C	HP Heater Drain to Condenser	2TED-BV-30
C	HP Heater Drain to Condenser	2TED-BV-35
C	HP Heater Drain to Condenser	2TED-BV-36
C	HP Heater Drain to Condenser	2TED-BV-37
C	HP Heater Drain to Condenser	2TED-BV-38

N - Non-critical

C - Critical

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LOW-PRESSURE HEATER DRAINS SYSTEM  
P&I DIAGRAM 2TEE-M2077

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
C	LP Htr Drains to Condenser	2TEE-BV-9
C	LP Htr Drains to Condenser	2TEE-BV-11
C	LP Htr Drains to Condenser	2TEE-BV-13
C	LP Htr Drains to Condenser	2TEE-BV-15
C	LP Htr Drains to Condenser	2TEE-BV-17
C	LP Htr Drains to Condenser	2TEE-BV-19
C	LP Htr Drains to Condenser	2TEE-BV-21
C	LP Htr Drains to Condenser	2TEE-BV-22
N	LP Htr Drains to Cycle Makeup	2TEE-BV-129

N - Non-critical

C - Critical

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HEATER VENTS AND MISCELLANEOUS DRAINS SYSTEM  
P&I DIAGRAMS 2TEF-M2078A AND M2078B

Relief valves, vents, and drains should be checked and isolated in accordance with previously discussed procedures.

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TURBINE SYSTEM  
P&I DIAGRAM 2TGA-M2079

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
N	Ventilator Valve	2TGA-ABV-2
N	Condenser Hood Sprays	2TGA-BV-5

N - Non-critical

C - Critical

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IP14\_000873

TURBINE SEALS AND DRAINS SYSTEM  
P&I DIAGRAMS 2TGC-M2080A AND M2080B

<u>Class</u>	<u>Description</u>	<u>Valve Number</u>
C	Main Steam Supply	2TGC-BV-10*
N	Main Steam Supply	2TGC-MBV-3*
N	Main Steam Supply	2TGC-MBV-2*
N	Main Steam Supply	2TGC-ACV-1*
N	Auxiliary Steam Supply	2TGC-MBV-6
N	Auxiliary Steam Supply	2TGC-ACV-5
N	Condensate to Steam Seal Desuperheater	2TGC-BV-25
N	Auxiliary Steam to Cold Reheat	2TGC-MBV-16
N	Auxiliary Steam to Cold Reheat	2TGC-BV-58
N	Reheat Valve Drain	2TGC-MBV-31
N	Reheat Valve Drain	2TGC-MBV-32
N	Control Valve/Stop Valve Drains	2TGC-MBV-33
N	Control Valve/Stop Valve Drains	2TGC-MBV-34
N	Control Valve/Stop Valve Drains	2TGC-MBV-35
N	Control Valve/Stop Valve Drains	2TGC-MBV-36
N	Control Valve/Stop Valve Drains	2TGC-MBV-37
N	Control Valve/Stop Valve Drains	2TGC-MBV-38
N	Control Valve/Stop Valve Drains	2TGC-MBV-39
N	Control Valve/Stop Valve Drains	2TGC-MBV-40
N	Steam Lead Drain	2TGC-MBV-49
N	HP Turb Leakoff to Steam Seals	2TGC-ACV-17

\*Requires full-time operator. Must be opened quickly on a turbine trip.

N - Non-critical

C - Critical

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## 5.0 SAMPLE CALCULATIONS

<u>Variable</u>	<u>Description</u>	<u>Test 6 Value</u>
TCND	Temperature of Condensate at Flow Section	295.8 F
PCND	Pressure of Condensate at Flow Section	141.2 psia
TAMB	Temperature of Ambient Air	90.3 F
G	Local Acceleration of Gravity	32.138 <sub>2</sub> ft/sec <sup>2</sup>
TFW08	Temperature of Feedwater out of Feedwater Heater 8	551.1 F
PFW08	Pressure of Feedwater out of Feedwater Heater 8	2733.9 psia
DPFWN	Differential Pressure Across Feedwater Flow Nozzle	58.113 psid
DPCNDNA	Differential Pressure Across Condensate Flow Nozzle Tap A	10.290 psid
DPCNDNB	Differential Pressure Across Condensate Flow Nozzle Tap B	10.280 psid
TFGRR	Temperature of Flue Gas Reheat Return Water	232.2 F
PFGRR	Pressure of Flue Gas Reheat Return Water	139.2 psia
DPFGRR	Differential Pressure Across Flue Gas Reheat Flow Nozzle	3.597 psid
TLO4	Temperature of Steam Leakage Number 4	602.4 F
PLO4	Pressure of Steam Leakage Number 4	118.3 psia
DPLO4	Differential Pressure of Steam Leakage Number 4	0.895 psid
TLO6	Temperature of Steam Leakage Number 6	692 F
PLO6	Pressure of Steam Leakage Number 6	118.3 psia
DPLO6	Differential Pressure of Steam Leakage Number 6	4.620 psid
TCLGLO	Temperature of IP Rotor Cooling Steam	818.1 F
PCLGLO	Pressure of IP Rotor Cooling Steam	521.0 psia
DPCLGLO	Differential Pressure of IP Rotor Cooling Steam	19.601 psid
TVSLO	Temperature of Valve Stem Leakoff Steam	886.5 F
PVSLO	Pressure of Valve Stem Leakoff Steam	521.0 psia
DPVSLO	Differential Pressure of Valve Stem Leakoff Steam	0.0 psid

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<u>Variable</u>	<u>Description</u>	<u>Test 6 Value</u>
TLO2	Temperature of Steam Leakage Number 2	886.5 F
PL02	Pressure of Steam Leakage Number 2	521.0 psia
PCL02	Packing Constant of Steam Leakage Number 2	50
TLO3	Temperature of Steam Leakage Number 3	971.9 F
PL03	Pressure of Steam Leakage Number 3	1,927.3 psia
PCL03	Packing Constant of Steam Leakage Number 3	540
TLO5	Temperature of Steam Leakage Number 5	582.4 F
PL05	Pressure of Steam Leakage Number 5	120.7 psia
PCL05	Packing Constant of Steam Leakage Number 5	800
TLO7	Temperature of Steam Leakage Number 7	682.6 F
PL07	Pressure of Steam Leakage Number 7	122.5 psia
PCL07	Packing Constant of Steam Leakage Number 7	980
TLO8	Temperature of Steam Leakage Number 8	635.5 F
PL08	Pressure of Steam Leakage Number 8	120.7 psia
PCL08	Packing Constant of Steam Leakage Number 8	550
TLO9	Temperature of Steam Leakage Number 9	645.7 F
PL09	Pressure of Steam Leakage Number 9	122.5 psia
PCL09	Packing Constant of Steam Leakage Number 9	550
TDV1A	Temperature of Steam Seals to Heater 1A	654.1 F
PDV1A	Pressure of Steam Seals to Heater 1A	5.031 psia
DPDV1A	Differential Pressure of Steam Seals to Heater 1A	0.037 psid
TCVCND	Temperature of Steam Seals to Condenser	654 F
PDVCND	Pressure of Steam Seals to Condenser	2.117 psia
DPDVCND	Differential Pressure of Steam Seals to Condenser	0.0 psid
TEXTBFPTA	Temperature of Extraction Steam at Boiler Feed Pump Turbine A	619.2 F
PEXTBFPTA	Pressure of Extraction Steam at Boiler Feed Pump Turbine A	119.3 psia
DPEXTBFPTA	Differential Pressure of Extraction Steam at Boiler Feed Pump Turbine A	6.216 psid
TEXTBFPTB	Temperature of Extraction Steam at Boiler Feed Pump Turbine B	619.1 F
PEXTBFPTB	Pressure of Extraction Steam at Boiler Feed Pump Turbine B	119.3 psia

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<u>Variable</u>	<u>Description</u>	<u>Test 6 Value</u>
DPEXTBFPTB	Differential Pressure of Extraction Steam at Boiler Feed Pump Turbine B	6.813 psid
SPBFPTA	Speed of Boiler Feed Pump Turbine A	5,292.6 rpm
HPBFPTA	Horsepower of Boiler Feed Pump Turbine A	12,347 hp
PFWP01A	Pressure of Boiler Feed Pump Discharge A	2,920.2 psia
TFWP01A	Temperature of Boiler Feed Pump Discharge A	345.9 F
PFWPI	Pressure of Boiler Feed Pump Inlet A	318.6 psia
TFWPI	Temperature of Boiler Feed Pump Inlet A	340.0 F
TCNDPD	Temperature of Condensate Pump Discharge	126.6 F
PCNDPD	Pressure of Condensate Pump Discharge	411.8 psia
PEXT8A	Pressure of Feedwater Heater 8A Extraction Steam	1,064.5 psia
TEXT8A	Temperature of Feedwater Heater 8A Extraction Steam	787.9 F
PEXT8B	Pressure of Feedwater Heater 8B Extraction Steam	1,060.7 psia
TEXT8B	Temperature of Feedwater Heater 8B Extraction Steam	788.2 F
PEXT7A	Pressure of Feedwater Heater 7A Extraction Steam	557.0 psia
TEXT7A	Temperature of Feedwater Heater 7A Extraction Steam	618.0 F
PEXT7B	Pressure of Feedwater Heater 7B Extraction Steam	557.0 psia
TEXT7B	Temperature of Feedwater Heater 7B Extraction Steam	618.5 F
PEXT6A	Pressure of Feedwater Heater 6A Extraction Steam	230.8 psia
TEXT6A	Temperature of Feedwater Heater 6A Extraction Steam	803.3 F
PEXT6B	Pressure of Feedwater Heater 6B Extraction Steam	229.0 psia
TEXT6B	Temperature of Feedwater Heater 6B Extraction Steam	800.8 F
PEXT5	Pressure of Deaerating Heater 5 Extraction Steam	118.3 psia
TEXT5	Temperature of Deaerating Heater 5 Extraction Steam	619.6 F

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<u>Variable</u>	<u>Description</u>	<u>Test 6 Value</u>
PEXT4	Pressure of Feedwater Heater 4 Extraction Steam	63.38 psia
TEXT4	Temperature of Feedwater Heater 4 Extraction Steam	515.8 F
PEXT3	Pressure of Feedwater Heater 3 Extraction Steam	37.94 psia
TEXT3	Temperature of Feedwater Heater 3 Extraction Steam	414.8 F
PEXT2	Pressure of Feedwater Heater 2 Extraction Steam	11.05 psia
TEXT2	Temperature of Feedwater Heater 2 Extraction Steam	233.9 F
PEXT1A	Pressure of Feedwater Heater 1A	4.880 psia
PEXT1B	Pressure of Feedwater Heater 1B	4.784 psia
PEXT1C	Pressure of Feedwater Heater 1C	5.476 psia
PFWECON	Pressure of Feedwater at Economizer	2,734 psia
PCNDO4	Pressure of Condensate out of Heater 4	174.5 psia
TDR8A	Temperature of Feedwater Heater 8A Drains	486.4 F
TDR8B	Temperature of Feedwater Heater 8B Drains	485.6 F
TDR7A	Temperature of Feedwater Heater 7A Drains	404.6 F
TDR7B	Temperature of Feedwater Heater 7B Drains	402.8 F
TDR6A	Temperature of Feedwater Heater 6A Drains	353.2 F
TDR6B	Temperature of Feedwater Heater 6B Drains	353.4 F
TDR4	Temperature of Feedwater Heater 4 Drains	269.0 F
TDR3	Temperature of Feedwater Heater 3 Drains	205.3 F
TDR2	Temperature of Feedwater Heater 2 Drains	167.9 F
TDR1	Temperature of Feedwater Heater 1 Drains	161.4 F
TFW08A	Temperature of Feedwater out of Feedwater Heater 8A	551.8 F
TFW07A	Temperature of Feedwater out of Feedwater Heater 7A	479.2 F
TFW06A	Temperature of Feedwater out of Feedwater Heater 6A	395.3 F
TFW08B	Temperature of Feedwater out of Feedwater Heater 8B	552.5 F
TFW07B	Temperature of Feedwater out of Feedwater Heater 7B	478.4 F

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<u>Variable</u>	<u>Description</u>	<u>Test 6 Value</u>
TFW06B	Temperature of Feedwater out of Feedwater Heater 6B	394.5 F
TFW05	Temperature of Feedwater out of Deaerating Heater 5	340.4 F
TCND04	Temperature of Condensate out of Feedwater Heater 4	296.6 F
TCND03	Temperature of Condensate out of Feedwater Heater 3	264.2 F
TCND02	Temperature of Condensate out of Feedwater Heater 2	195.8 F
TCND01A	Temperature of Condensate out of Feedwater Heater 1A	160.9 F
TCND01B	Temperature of Condensate out of Feedwater Heater 1B	160.1 F
TCND01C	Temperature of Condensate out of Feedwater Heater 1C	160.7 F
TCNDI4	Temperature of Condensate into Feedwater Heater 4	264.2 F
TCNDI3	Temperature of Condensate into Feedwater Heater 3	196.6 F
TCNDI2	Temperature of Condensate into Feedwater Heater 2	160.0 F
TCNDI1	Temperature of Condensate into Feedwater Heater 1	133.4 F
TCNDIDC	Temperature of Condensate into Drain Cooler	127.6 F
PCNDI5	Pressure of Condensate into Deaerator	141.2 psia
PCNDDCI	Pressure of Condensate into Drain Cooler	222.2 psia
PEXTS4	Pressure of Steam at Stage 4 Extraction	1,075.4 psia
TEXTS4	Temperature of Steam at Stage 4 Extraction	790.2 F
PCRH	Pressure of Cold Reheat Steam	571.5 psia
TCRH	Temperature of Cold Reheat Steam	619.1 F
PEXTS11	Pressure of Steam at Stage 11 Extraction	231.6 psia
TEXTS11	Temperature of Steam at Stage 11 Extraction	803.5 F
PEXTS14	Pressure of Steam at Stage 14 Extraction	121.6 psia
TEXTS14	Temperature of Steam at Stage 14 Extraction	622.2 F
PEXTS15	Pressure of Steam at Stage 15 Extraction	64.6 psia
TEXTS15	Temperature of Steam at Stage 15 Extraction	526.6 F
PEXTS16	Pressure of Steam at Stage 16 Extraction	39.33 psia

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<u>Variable</u>	<u>Description</u>	<u>Test 6 Value</u>
TEXTS16	Temperature of Steam at Stage 16 Extraction	422.4 F
PEXTS18	Pressure of Steam at Stage 18 Extraction	11.52 psia
TEXTS18	Temperature of Steam at Stage 18 Extraction	233.8 F
PEXTS19	Pressure of Steam at Stage 19 Extraction	4.943 psia
PHDA	Pressure of Condenser Hood A	2.056 psia
PHDB	Pressure of Condenser Hood B	1.980 psia
PHDC	Pressure of Condenser Hood C	1.267 psia
TMS	Temperature of Main Steam	996.5 F
PMS	Pressure of Main Steam	2,394.1 psia
THRH	Temperature of Hot Reheat Steam	1,003.1 F
PHRH	Pressure of Hot Reheat Steam	527.6 psia
PHRHB	Pressure of Hot Reheat Steam at IP Turbine Bowl	521.0 psia
PCXO	Pressure of Crossover Steam	118.6 psia
TCXOB	Temperature of Crossover Steam at LP Turbine Bowl	618.8 F
PCNDS	Pressure of Condenser, Specified	1.5 in. Hg
DPBFP1A	Differential Pressure of Seal Injection Water to Boiler Feed Pump 1A	3.095 psid
DPBFP1B	Differential Pressure of Seal Injection Water to Boiler Feed Pump 1B	1.119 psid
DPBFP1C	Differential Pressure of Seal Injection Water to Boiler Feed Pump 1C	11.162 psid
DPBFP2A	Differential Pressure of Seal Injection Water to Booster Boiler Feed Pump 2A	2.468 psid
DPBFP2B	Differential Pressure of Seal Injection Water to Booster Boiler Feed Pump 2B	6.487 psid
DPBFP2C	Differential Pressure of Seal Injection Water to Booster Boiler Feed Pump 2C	6.172 psid
TCWOA	Temperature of Circulating Water out of HP Condenser A	117.9 F
TCWOB	Temperature of Circulating Water out of IP Condenser B	116.2 F
TCWOC	Temperature of Circulating Water out of LP Condenser C	100.5 F
TCWIA	Temperature of Circulating Water into HP Condenser A	100.5 F

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<u>Variable</u>	<u>Description</u>	<u>Test 6 Value</u>
TCWIB	Temperature of Circulating Water into IP Condenser B	86.5 F
TCWIC	Temperature of Circulating Water into LP Condenser C	86.5 F
TIME	Time Length of Test	2 hours
PHACNT	Phase A Watt Meter Counts	20,093
PHBCNT	Phase B Watt Meter Counts	20,088
PHCCNT	Phase C Watt Meter Counts	19,818
PHAV	Phase A Secondary Volts	129.374
PHBV	Phase B Secondary Volts	129.172
PHCV	Phase C Secondary Volts	128.565
PHAA	Phase A Secondary Amps	3.884
PHBA	Phase B Secondary Amps	3.924
PHCA	Phase C Secondary Amps	3.911
PDRUM	Boiler Drum Pressure	2,667.4 psia

<u>Variable</u>	<u>Description</u>	<u>Test 6 Calculated Value</u>
QGEN	Generator Output	860,776 kW
APF	Average Power Factor	0.9891
VSTD	Specific Volume Water at Standard Conditions	0.01605 ft <sup>3</sup> /lb <sub>m</sub>
VCND	Specific Volume of Condensate at Flow Section	0.01740 ft <sup>3</sup> /lb <sub>m</sub>
VAMBC	Specific Volume of Condensate at Ambient Temperature at Flow Section	0.01610 ft <sup>3</sup> /lb <sub>m</sub>
VFW	Specific Volume of Feedwater at Feedwater Flow Nozzle	0.021209 ft <sup>3</sup> /lb <sub>m</sub>
VFGR	Specific Volume of Flue Gas Reheat at Flow Nozzle	0.01685 ft <sup>3</sup> /lb <sub>m</sub>
VLO4	Specific Volume of Leakoff Steam Number 4	5.2507 ft <sup>3</sup> /lb <sub>m</sub>
VLO6	Specific Volume of Leakoff Steam Number 6	5.7218 ft <sup>3</sup> /lb <sub>m</sub>
VCLGLO	Specific Volume of IP Rotor Cooling Steam	1.4033 ft <sup>3</sup> /lb <sub>m</sub>

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Variable	Description	Test 6 Calculated Value
VVSL0	Specific Volume of Valve Stem Leakoff	1.490 ft <sup>3</sup> /lb <sub>m</sub>
VLO2	Specific Volume of Steam Leakage Number 2	1.490 ft <sup>3</sup> /lb <sub>m</sub>
VLO5	Specific Volume of Steam Leakage Number 5	5.039 ft <sup>3</sup> /lb <sub>m</sub>
VLO7	Specific Volume of Steam Leakage Number 7	5.478 ft <sup>3</sup> /lb <sub>m</sub>
VLO8	Specific Volume of Steam Leakage Number 8	5.316 ft <sup>3</sup> /lb <sub>m</sub>
VLO9	Specific Volume of Steam Leakage Number 9	5.291 ft <sup>3</sup> /lb <sub>m</sub>
HLO4	Enthalpy of Steam Leakage Number 4	1,329.22 Btu/lb <sub>m</sub>
HLO6	Enthalpy of Steam Leakage Number 6	1,374.27 Btu/lb <sub>m</sub>
HLO2	Enthalpy of Steam Leakage Number 2	1,458.48 Btu/lb <sub>m</sub>
HLO5	Enthalpy of Steam Leakage Number 5	1,318.93 Btu/lb <sub>m</sub>
HLO7	Enthalpy of Steam Leakage Number 7	1,369.32 Btu/lb <sub>m</sub>
HLO8	Enthalpy of Steam Leakage Number 8	1,345.70 Btu/lb <sub>m</sub>
HLO9	Enthalpy of Steam Leakage Number 9	1,350.71 Btu/lb <sub>m</sub>
VDV1A	Specific Volume of Steam Seals Steam to Heater 1A	131.75 ft <sup>3</sup> /lb <sub>m</sub>
HDV1A	Enthalpy of Steam Seals to Heater 1A	1,361.95 Btu/lb <sub>m</sub>
VEXTBFPTA	Specific Volume of Boiler Feed Pump Turbine A Extraction Steam	5.2977 ft <sup>3</sup> /lb <sub>m</sub>
VEXTBFPTB	Specific Volume of Boiler Feed Pump Turbine B Extraction Steam	5.2938 ft <sup>3</sup> /lb <sub>m</sub>
HBFPPTA	Enthalpy of Boiler Feed Pump Turbine A Throttle Steam	1,337.62 Btu/lb <sub>m</sub>
VFWPDA	Specific Volume of Feedwater at Boiler Feed Pump A Discharge	0.017701 ft <sup>3</sup> /lb <sub>m</sub>

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Variable	Description	Test 6 Calculated Value
VFWPIA	Specific Volume of Feedwater at Boiler Feed Pump A Inlet	0.017853 ft <sup>3</sup> /lb <sub>m</sub>
VCNDPD	Specific Volume of Condensate at Condensate Pump Discharge	0.01621 ft <sup>3</sup> /lb <sub>m</sub>
HEXT8A	Enthalpy of Feedwater Heater 8A Extraction Steam	1,377.78 Btu/lb <sub>m</sub>
HEXT8B	Enthalpy of Feedwater Heater 8B Extraction Steam	1,378.17 Btu/lb <sub>m</sub>
HEXT7A	Enthalpy of Feedwater Heater 7A Extraction Steam	1,304.60 Btu/lb <sub>m</sub>
HEXT7B	Enthalpy of Feedwater Heater 7B Extraction Steam	1,304.90 Btu/lb <sub>m</sub>
HEXT6A	Enthalpy of Feedwater Heater 6A Extraction Steam	1,425.76 Btu/lb <sub>m</sub>
HEXT6B	Enthalpy of Feedwater Heater 6B Extraction Steam	1,424.53 Btu/lb <sub>m</sub>
HEXT5	Enthalpy of Feedwater Heater 5 Extraction Steam	1,337.83 Btu/lb <sub>m</sub>
HEXT4	Enthalpy of Feedwater Heater 4 Extraction Steam	1,290.46 Btu/lb <sub>m</sub>
HEXT3	Enthalpy of Feedwater Heater 3 Extraction Steam	1,243.89 Btu/lb <sub>m</sub>
HEXT2	Enthalpy of Feedwater Heater 2 Extraction Steam	1,162.29 Btu/lb <sub>m</sub>
HEXT1	Enthalpy of Feedwater Heater 1 Extraction Steam	1,090 Btu/lb <sub>m</sub>
TSEXT8A	Temperature of Feedwater Heater 8A Saturated Steam	552.22 F
TSEXT8B	Temperature of Feedwater Heater 8B Saturated Steam	551.78 F
TSEXT7A	Temperature of Feedwater Heater 7A Saturated Steam	478.27 F
TSEXT7B	Temperature of Feedwater Heater 7B Saturated Steam	478.27 F
TSEXT6A	Temperature of Feedwater Heater 6A Saturated Steam	394.00 F
TSEXT6B	Temperature of Feedwater Heater 6B Saturated Steam	393.33 F

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		Test 6 Calculated Value
Variable	Description	
TSEXT5	Temperature of Feedwater Heater 5 Saturated Steam	340.22 F
TSEXT4	Temperature of Feedwater Heater 4 Saturated Steam	296.30 F
TSEXT3	Temperature of Feedwater Heater 3 Saturated Steam	264.17 F
TSEXT2	Temperature of Feedwater Heater 2 Saturated Steam	197.95 F
TSEXT1A	Temperature of Feedwater Heater 1A Saturated Steam	161.17 F
TSEXT1B	Temperature of Feedwater Heater 1B Saturated Steam	160.34 F
TSEXT1C	Temperature of Feedwater Heater 1C Saturated Steam	166.07 F
HDR8A	Enthalpy of Feedwater Heater 8A Drains	471.72 Btu/lb <sub>m</sub>
HDR8B	Enthalpy of Feedwater Heater 8B Drains	470.80 Btu/lb <sub>m</sub>
HRD7A	Enthalpy of Feedwater Heater 7A Drains	380.42 Btu/lb <sub>m</sub>
HDR7B	Enthalpy of Feedwater Heater 7B Drains	378.47 Btu/lb <sub>m</sub>
HDR6A	Enthalpy of Feedwater Heater 6A Drains	325.29 Btu/lb <sub>m</sub>
HDR6B	Enthalpy of Feedwater Heater 6B Drains	325.56 Btu/lb <sub>m</sub>
HDR5	Enthalpy of Feedwater Heater 5 Drains	311.68 Btu/lb <sub>m</sub>
HDR4	Enthalpy of Feedwater Heater 4 Drains	237.99 Btu/lb <sub>m</sub>
HDR3	Enthalpy of Feedwater Heater 3 Drains	173.50 Btu/lb <sub>m</sub>
HDR2	Enthalpy of Feedwater Heater 2 Drains	135.84 Btu/lb <sub>m</sub>
HDR1	Enthalpy of Feedwater Heater 1 Drains	129.35 Btu/lb <sub>m</sub>
HFWO8A	Enthalpy of Feedwater out of Feedwater Heater 8A	548.25 Btu/lb <sub>m</sub>

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		Test 6 Calculated Value
Variable	Description	
HFWO8B	Enthalpy of Feedwater out of Feedwater Heater 8B	549.13 Btu/lb <sub>m</sub>
HFWO7A	Enthalpy of Feedwater out of Feedwater Heater 7A	463.97 Btu/lb <sub>m</sub>
HFWO7B	Enthalpy of Feedwater out of Feedwater Heater 7B	463.04 Btu/lb <sub>m</sub>
HFWO6A	Enthalpy of Feedwater out of Feedwater Heater 6A	373.42 Btu/lb <sub>m</sub>
HFWO6B	Enthalpy of Feedwater out of Feedwater Heater 6B	372.56 Btu/lb <sub>m</sub>
HFWI6A	Enthalpy of Feedwater into Feedwater Heater 6A	321.76 Btu/lb <sub>m</sub>
HFWI6B	Enthalpy of Feedwater into Feedwater Heater 6B	321.49 Btu/lb <sub>m</sub>
HFWO5	Enthalpy of Feedwater out of Feedwater Heater 5	311.68 Btu/lb <sub>m</sub>
HCNDO4	Enthalpy of Condensate out of Feedwater Heater 4	266.42 Btu/lb <sub>m</sub>
HCNDO3	Enthalpy of Condensate out of Feedwater Heater 3	233.29 Btu/lb <sub>m</sub>
HCNDO2	Enthalpy of Condensate out of Feedwater Heater 2	164.30 Btu/lb <sub>m</sub>
HCNDO1A	Enthalpy of Condensate out of Feedwater Heater 1A	129.32 Btu/lb <sub>m</sub>
HCNDO1B	Enthalpy of Condensate out of Feedwater Heater 1B	128.53 Btu/lb <sub>m</sub>
HCNDO1C	Enthalpy of Condensate out of Feedwater Heater 1C	129.16 Btu/lb <sub>m</sub>
HCNDI5	Enthalpy of Condensate into Feedwater Heater 5	265.64 Btu/lb <sub>m</sub>
HCNDI4	Enthalpy of Condensate into Feedwater Heater 4	233.36 Btu/lb <sub>m</sub>
HCNDI3	Enthalpy of Condensate into Feedwater Heater 3	165.07 Btu/lb <sub>m</sub>
HCNDI2	Enthalpy of Condensate into Feedwater Heater 2	128.40 Btu/lb <sub>m</sub>
HCNDI1	Enthalpy of Condensate into Feedwater Heater 1	101.89 Btu/lb <sub>m</sub>

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Variable	Description	Test 6 Calculated Value
HEXTS4	Enthalpy of Stage 4 Extraction Steam	1,378.64 Btu/lb <sub>m</sub>
HCRH	Enthalpy of Cold Reheat Steam	1,304.12 Btu/lb <sub>m</sub>
HEXTS11	Enthalpy of Stage 11 Extraction Steam	1,425.82 Btu/lb <sub>m</sub>
HEXTS14	Enthalpy of Stage 14 Extraction Steam	1,338.93 Btu/lb <sub>m</sub>
HEXTS15	Enthalpy of Stage 15 Extraction Steam	1,295.66 Btu/lb <sub>m</sub>
HEXTS16	Enthalpy of Stage 16 Extraction Steam	1,247.42 Btu/lb <sub>m</sub>
HEXTS18	Enthalpy of Stage 18 Extraction Steam	1,162.10 Btu/lb <sub>m</sub>
HEXTS19	Enthalpy of Stage 19 Extraction Steam	1,090 Btu/lb <sub>m</sub>
HCND	Enthalpy of Condenser 1A Hot Well Saturated Water	95.04 Btu/lb <sub>m</sub>
HMS	Enthalpy of Main Steam	1,458.48 Btu/lb <sub>m</sub>
SMS	Entropy of Main Steam	1.531348 Btu/lb <sub>m</sub> R
HHPS	Enthalpy of High-Pressure Turbine Exhaust Steam at Constant Entropy	1,283.72 Btu/lb <sub>m</sub>
HHRH	Enthalpy of Hot Reheat Steam	1,521.65 Btu/lb <sub>m</sub>
SHRH	Entropy of Hot Reheat Steam	1.733338 Btu/lb <sub>m</sub> R
HCXO	Enthalpy of Intermediate Pressure Turbine Exhaust Steam	1,337.42 Btu/lb <sub>m</sub>
HIPS	Enthalpy of Intermediate Pressure Turbine Exhaust Steam at Constant Entropy	1,322.51 Btu/lb <sub>m</sub>
SCXO	Entropy of Low-Pressure Turbine Bowl Steam	1.747345 Btu/lb <sub>m</sub> R
HLPS	Enthalpy of Low-Pressure Turbine Exhaust Steam at Constant Entropy	1,007.98 Btu/lb <sub>m</sub>
HCNDPD	Enthalpy of Condensate at Condensate Pump Discharge	95.61 Btu/lb <sub>m</sub>

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Variable	Description	Test 6 Calculated Value
HHWA	Enthalpy of HP Condenser 1A Hot Well	95.04 Btu/lb <sub>m</sub>
HHWB	Enthalpy of IP Condenser 1B Hot Well	93.66 Btu/lb <sub>m</sub>
HHWC	Enthalpy of LP Condenser 1C Hot Well	77.77 Btu/lb <sub>m</sub>
HAMB	Enthalpy of Saturated Water	171.8 Btu/lb <sub>m</sub>
HAMBCW	Enthalpy of Circulating Water at Ambient Temperature and Pressure	35.37 Btu/lb <sub>m</sub>
HDRUM	Boiler Drum Enthalpy	753.2 Btu/lb <sub>m</sub>

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# CALCULATION OF CONDENSATE FLOW

$$FCND = C \times K_M \times [(DPCND \times 33.9 \text{ ft H}_2\text{O} \times VCND)/(14.696 \text{ psia} \times VSTD)]^{0.5}$$

$$\times \frac{3600 \text{ sec}}{1 \text{ h}} \times \frac{1}{VCND} \times \frac{\text{ft}^3}{\text{lb}_m}$$

$$K_M = \frac{A \times (2 \times G)^{0.5} \times F_A}{(1-B^4)^{0.5}}$$

$$A = \text{Nozzle Throat Area} = 0.5283 \text{ ft}^2$$

$$G = \text{Local Acceleration of Gravity} = 32.138 \text{ ft/sec}^2$$

$$F_A = \text{Nozzle Temperature Expansion Factor} = 1.0040$$

$$B = \text{Ratio of Throat Diameter to Pipe Diameter} = 0.4233$$

$$K_M = 4.32240$$

$$C = \text{Nozzle Discharge Coefficient} = 0.9977$$

$$FCND = 4,525,831 \text{ lb}_m/\text{h}$$

# CALCULATION OF FEEDWATER FLOW FROM NOZZLE PRESSURE DROP

$$FFW = C \times K_M \times [(DPFWN \times 33.9 \text{ ft H}_2\text{O} \times VFW)/(14.696 \text{ psia} \times VSTD)]^{0.5}$$

$$\times \frac{3600 \text{ sec}}{1 \text{ h}} \times \frac{1}{VFW} \times \frac{\text{ft}^3}{\text{lb}_m}$$

$$A = 0.3323 \text{ ft}^2$$

$$B = 0.4836$$

$$F_A = 1.0091$$

$$C = 0.9980$$

$$FFW = 6,234,122 \text{ lb}_m/\text{h}$$

# CALCULATION OF FLUE GAS REHEAT FLOW

$$FFGR = \frac{0.525 \text{ in.}}{\text{ft}^{1/2} \text{ sec}} \times D^2 \times C \times F_A \times (DPFGR \times VFGR)^{0.5} \times 3600 \times \frac{1}{VFGR}$$

D = Diameter of Orifice = 7.2037 in.

C = 0.65

F<sub>A</sub> = 1.0030

FFGR = 934,100 lb<sub>m</sub>/h

## CALCULATION OF STEAM LEAKAGE NUMBER 4 FLOW

$$FLO4 = 1890.07 \times D^2 \times K \times E \times Y \times [DPLO4/VLO4]^{0.5}$$

D = Orifice Diameter = 3.216 in.

B = 0.799

K = Nozzle Discharge Coefficient = 0.7800

E = Nozzle Expansion Factor =  $1 + 2 (9 \times 10^{-6}) (TLO4-70F)$  = 1.0096

Y = Expansion Factor for Compressible Flow =

$$1 - (0.41 + 0.35 B^4) \frac{DPLO4}{PLO4 \times (1.3)} = 0.99678$$

FLO4 = 6,345 lb<sub>m</sub>/h

## CALCULATION OF STEAM LEAKAGE NUMBER 6 FLOW

$$FLO6 = 1890.07 \times D^2 \times K \times E \times Y \times [DPLO6/VLO6]^{0.5}$$

D = 2.890 in.

B = 0.7178

K = 0.7130

E = 1.0112

Y = 0.9849

FLO6 = 10,088 lb<sub>m</sub>/h

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#### CALCULATION OF IP ROTOR COOLING STEAM FLOW

$$FCLGLO = 1890.07 \times D^2 \times K \times E \times Y \times [DPCLGLO/VCLGLO]^{0.5}$$

$$D = 2.00 \text{ in.}$$

$$B = 0.5227$$

$$K = 0.627$$

$$E = 1.0135$$

$$Y = 0.9874$$

$$FCLGLO = 17,755 \text{ lb}_m/\text{h}$$

#### CALCULATION OF VALVE STEM LEAKOFF FLOW

$$FVSLO = 1890.07 \times D^2 \times K \times E \times Y \times [DPVSLO/VVSLO]^{0.5}$$

$$D = 1.818 \text{ in.}$$

$$B = 0.7826$$

$$K = 0$$

$$FVSLO = 0 \text{ lb}_m/\text{h}$$

#### CALCULATION OF STEAM LEAKOFFS 2, 5, 7, 8, AND 9

$$FLO = (PLO/VLO)^{0.5} \times PC$$

$$FLO2 = 935 \text{ lb}_m/\text{h}$$

$$FLO3 = 37,503 \text{ lb}_m/\text{h}$$

$$FLO5 = 3,916 \text{ lb}_m/\text{h}$$

$$FLO7 = 4,634 \text{ lb}_m/\text{h}$$

$$FLO8 = 2,621 \text{ lb}_m/\text{h}$$

$$FLO9 = 2,646 \text{ lb}_m/\text{h}$$

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CALCULATION OF STEAM SEALS FLOW TO HEATER 1A

$$FDV1A = 1890.07 \times D^2 \times K \times [DPDV1A/VDV1A]^{0.5}$$

$$D = 12.000 \text{ in.}$$

$$K = 0.76$$

$$FDV1A = 3,466 \text{ lb}_m/\text{h}$$

CALCULATION OF STEAM SEALS FLOW TO CONDENSER

$$FDVCND = 1890.07 \times D^2 \times K \times [DPDVCND/VDVCND]^{0.5}$$

$$D = 10.020 \text{ in.}$$

$$K = 0.76$$

$$FDVCND = 0 \text{ lb}_m/\text{h}$$

CALCULATION OF BOILER FEED PUMP TURBINE STEAM FLOW

$$FSBFPT = 358.93 \times C \times Y \times F_A \times D^2 \times [(DPEXTBFPT \times 406.8 \text{ in. H}_2\text{O}) / (14.696 \text{ psia} \times VEXTBFPT)]^{0.5} / (1-B^4)$$

$$D = 7.809 \text{ in.}$$

$$C_A = 0.997$$

$$F_A = 1.0105$$

$$Y = 0.970$$

$$B = 0.45269$$

$$FSBFPTA = 124,730 \text{ lb}_m/\text{h}$$

$$C_A = 0.997$$

$$F_A = 1.0105$$

$$Y = 0.968$$

$$FSBFPTB = 130,361 \text{ lb}_m/\text{h}$$



# CALCULATION OF BOILER FEED PUMP SEAL INJECTION FLOWS

$$\text{FBFPI} = 0.0438 \times C \times D^2 \times F_A \times (\text{DPBFPI} \times 33.9 \text{ ft H}_2\text{O}/14.696 \text{ psia})^{0.5} \\ \times 3600 \frac{\text{sec}}{\text{h}} \times \frac{1}{\text{VCNDPD}}$$

$$F_A = 1.001$$

$$D_1 = 0.9522 \text{ in.}$$

$$B_1 = 0.49106$$

$$C_{1A} = 0.620$$

$$C_{1B} = 0.620$$

$$C_{1C} = 0.619$$

$$\text{FBFP1AI} = 14,622 \text{ lb}_m/\text{h}$$

$$\text{FBFP1BI} = 8,792 \text{ lb}_m/\text{h}$$

$$\text{FBFP1CI} = 27,724 \text{ lb}_m/\text{h}$$

$$D_2 = 0.92515 \text{ in.}$$

$$B_2 = 0.6168$$

$$C_{2A} = 0.658$$

$$C_{2B} = 0.657$$

$$C_{2C} = 0.657$$

$$\text{FBFP2AI} = 13,083 \text{ lb}_m/\text{h}$$

$$\text{FBFP2BI} = 21,178 \text{ lb}_m/\text{h}$$

$$\text{FBFP2CI} = 20,657 \text{ lb}_m/\text{h}$$

$$\text{FBFP1RJ} = \text{Boiler Feed Pump Rejected Seal Injection Flow} = 18,560 \text{ lb}_m/\text{h}$$

$$\text{FBFP2RJ} = \text{Booster Feed Pump Rejected Seal Injection Flow} = 47,275 \text{ lb}_m/\text{h}$$

$$\text{FMSA} = \text{Flow of Main Steam Attenuator} = 0 \text{ lb}_m/\text{h}$$

$$\text{FBFPSIR} = \text{Boiler Feed Pump Retained Seal Injection Water}$$

$$= \text{FBFPI} - (\text{FBFP1RJ} + \text{FBFP2RJ})$$

$$= 40,221 \text{ lb}_m/\text{h}$$

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# CALCULATION OF FEEDWATER HEATER 8 EXTRACTION FLOWS

(Assume half of feedwater flow through each feedwater heater string and no heat loss from heaters)

$$\begin{aligned} \text{FEXT8A} &= \frac{\text{FFW} (\text{HFWO8A} - \text{HFWO7A})}{2 (\text{HEXT8A} - \text{HDR8A})} \\ &= 0.04651 \text{ FFW} \end{aligned}$$

$$\begin{aligned} \text{FEXT8B} &= \frac{\text{FFW} (\text{HFWO8B} - \text{HFWO7B})}{2 (\text{HEXT8B} - \text{HDR8B})} \\ &= 0.04744 \text{ FFW} \end{aligned}$$

# CALCULATION OF FEEDWATER HEATER 7 EXTRACTION FLOWS

$$\begin{aligned} \text{FEXT7A} &= \frac{\text{FFW} (0.5)(\text{HFWO7A} - \text{HFWO6A}) + \text{FEXT8A} (\text{HDR7A} - \text{HDR8A})}{(\text{HEXT7A} - \text{HDR7A})} \\ &= 0.04439 \text{ FFW} \end{aligned}$$

$$\begin{aligned} \text{FEXT7B} &= \frac{\text{FFW} (0.5)(\text{HFWO7B} - \text{HFWO6B}) + \text{FEXT8B} (\text{HDR7B} - \text{HDR8B})}{(\text{HEXT7B} - \text{HDR7B})} \\ &= 0.04410 \text{ FFW} \end{aligned}$$

# CALCULATION OF FEEDWATER HEATER 6 EXTRACTION FLOWS

$$\begin{aligned} \text{FEXT6A} &= \frac{\text{FFW} (0.5) (\text{HFWO6A} - \text{HFWI6A}) + (\text{FEXT7A} + \text{FEXT8A}) (\text{HDR6A} - \text{HDR7A})}{(\text{HEXT6A} - \text{HDR6A})} \\ &= 0.01892 \text{ FFW} \end{aligned}$$

$$\begin{aligned} \text{FEXT6B} &= \frac{\text{FFW} (0.5) (\text{HFWO6B} - \text{HFWI6B}) + (\text{FEXT7B} + \text{FEXT8B}) (\text{HDR6B} - \text{HDR7B})}{(\text{HEXT6B} - \text{HDR6B})} \\ &= 0.01883 \text{ FFW} \end{aligned}$$

#### CALCULATION OF DEAERATING HEATER 5 EXTRACTION FLOW

##### HEAT BALANCE AROUND HEATER 5

$$\begin{aligned} \text{FEXT5} = & [(\text{FFW} - \text{FBFPSIR} + \text{FMSA})(\text{HFWO5}) - \text{FCND}(\text{HCNDI5}) - \\ & (\text{FEXT8A} + \text{FEXT7A} + \text{FEXT6A})(\text{HDR6A}) - (\text{FEXT8B} + \text{FEXT7B} + \text{FEXT6B}) \\ & (\text{HDR6B}) - \text{FFGR}(\text{HFGRR} - \text{HFWO5}) - \text{FLO4}(\text{HLO4}) - \text{FLO6}(\text{HLO6})] / \text{HEXT5} \end{aligned}$$

$$\text{FEXT5} = 0.17941 \text{ FFW} - 847,297 \text{ lb}_m/\text{h}$$

##### MASS BALANCE AROUND HEATER 5

$$\begin{aligned} \text{FEXT5} = & \text{FFW} - \text{FBFPSIR} + \text{FMSA} - \text{FCND} - \text{FLO4} - \text{FLO6} - \text{FEXT8A} - \text{FEXT7A} - \\ & \text{FEXT6A} - \text{FEXT8B} - \text{FEXT7B} - \text{FEXT6B} \end{aligned}$$

$$\text{FEXT5} = 0.77981 \text{ FFW} - 4,582,485 \text{ lb}_m/\text{h}$$

##### SOLVING EQUATIONS SIMULTANEOUSLY

$$\text{FFW} = 6,221,229 \text{ lb}_m/\text{h}$$

##### THUS SOLVING FOR HEATER EXTRACTION FLOWS

$$\text{FEXT8A} = 289,343 \text{ lb}_m/\text{h}$$

$$\text{FEXT8B} = 295,131 \text{ lb}_m/\text{h}$$

$$\text{FEXT7A} = 276,190 \text{ lb}_m/\text{h}$$

$$\text{FEXT7B} = 274,386 \text{ lb}_m/\text{h}$$

$$\text{FEXT6A} = 117,692 \text{ lb}_m/\text{h}$$

$$\text{FEXT6B} = 117,133 \text{ lb}_m/\text{h}$$

$$\text{FEXT5} = 268,869 \text{ lb}_m/\text{h}$$

#### CALCULATION OF FEEDWATER HEATER 4 EXTRACTION FLOW

$$\text{FEXT4} = \frac{\text{FCND}(\text{HCNDO4} - \text{HCNDI4})}{(\text{HEXT4} - \text{HDR4})}$$

$$\text{FEXT4} = 142,165 \text{ lb}_m/\text{h}$$

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#### CALCULATION OF FEEDWATER HEATER 3 EXTRACTION FLOW

$$FEXT3 = \frac{FCND (HCND03 - HCNDI3) + FEXT4 (HDR3 - HDR4)}{(HEXT3 - HDR3)}$$

$$FEXT3 = 279,883 \text{ lb}_m/\text{h}$$

#### CALCULATION OF FEEDWATER HEATER 2 EXTRACTION FLOW

$$FEXT2 = \frac{FCND (HCND02 - HCNDI2) + (FEXT3 + FEXT4)(HDR2 - HDR3)}{(HEXT2 - HDR2)}$$

$$FEXT2 = 142,806 \text{ lb}_m/\text{h}$$

#### CALCULATION OF FEEDWATER HEATER 1 EXTRACTION FLOW

$$FEXT1A = \frac{FCND (0.3333)(HCND01A - HCNDI1) + FDV1A (HDR1 - HDV1A)}{(HEXT1A - HDR1)}$$

$$FEXT1A = 38,629 \text{ lb}_m/\text{h}$$

$$FEXT1B = \frac{FCND (HCND01B - HCNDI1)}{3 (HEXT1B - HDR1)}$$

$$FEXT1B = 41,836 \text{ lb}_m/\text{h}$$

$$FEXT1C = \frac{FCND (HCND01C - HCNDI1)}{3 (HEXT1C - HDR1)}$$

$$FEXT1C = 42,825 \text{ lb}_m/\text{h}$$

Generator output is calculated with the equations provided in the Appendix.

Test turbine stage flows and condenser flows are then calculated by performing a mass balance around the turbine.

The used energy end point of the turbine is calculated by performing a heat balance around the turbine using the measured generator output and measured condenser flow.

The expansion line end point (ELEP) of the turbine is then iterated by assuming a steam quality at the test exhaust pressure and calculating the ELEP. This is done until the ELEP between successive iterations varies less than 0.1 Btu/lb<sub>m</sub>.

The turbine stage efficiencies are then calculated as follows.

$$\text{HPEFF} = \text{High-Pressure Efficiency} = \frac{(\text{HMS} - \text{HCRH})}{(\text{HMS} - \text{HHPS})} \times 100 \text{ percent} = 88.33 \text{ percent}$$

$$\begin{aligned} \text{IPEFF} &= \text{Intermediate Pressure Efficiency} = \frac{(\text{HHRH} - \text{HCXO})}{(\text{HHRH} - \text{HIPS})} \times 100 \text{ percent} \\ &= 92.51 \text{ percent} \end{aligned}$$

$$\begin{aligned} \text{LPEFFE} &= \text{Low-Pressure Expansion Line End Point Efficiency} \\ &= \frac{(\text{HCXO} - \text{ELEP})}{(\text{HCXO} - \text{HLPS})} \times 100 \text{ percent} = 93.06 \text{ percent} \end{aligned}$$

$$\begin{aligned} \text{LPEFFU} &= \text{Low-Pressure Used Energy End Point Efficiency} \\ &= \frac{(\text{HCXO} - \text{UEEP})}{(\text{HCXO} - \text{HLPS})} \times 100 \text{ percent} = 90.63 \text{ percent} \end{aligned}$$

#### GROUP 1 CORRECTIONS

To accurately compare the test results from each load against the guarantee heat rate, it is necessary to correct the cycle from actual test conditions to specified conditions.

This is accomplished by calculating the test main steam flow and then assuming the following specified conditions.

- (1) No main or reheat steam attemperation.
- (2) No change in water level in the system or makeup.
- (3) No boiler feed pump seal injection.
- (4) Specified terminal difference and subcooler approach temperatures in the feedwater heaters.
- (5) Specified enthalpy rise across the condensate, boiler, and booster boiler feed pumps.
- (6) No subcooling of condensate leaving the condenser.
- (7) Specified pressure drops in feedwater heater extraction lines.
- (8) Seventy-five percent engine efficiency of boiler feed pump-boiler feed pump turbines.
- (9) No heat loss from extraction lines.
- (10) Specified flue gas reheat heat loss from deaerator.

Test flow/stage pressure ratios are calculated after each stage in the turbine with test temperatures and stage pressures. Then, new extraction flows are calculated using specified extraction line pressure drops, feedwater heater temperature differences, and all other specified conditions as stated previously.

New boiler feed pump turbine steam flows were calculated from the General Electric design heat balances and using 75 percent engine efficiency since the boiler feed pump turbines were not tested.

Test Relationship	W-lb <sub>m</sub> /h	P-psia	W/P
Throttle Flow	6,221,229		
Valve Stem Leakoff	-935		
IP Cooling Leakoff	-17,755		
No. 3 Gland Leakoff	-37,503		
No. 8 Extraction Flow	-584,474		
Steam Flow Following Extraction	5,580,562	1,075.375	5,189.41
No. 4 Gland Leakoff	-6,345		
No. 5 Gland Leakoff	-3,916		
No. 6 Gland Leakoff	-10,088		
No. 7 Gland Leakoff	-4,634		
No. 7 Extraction Flow	-550,575		
No. 3 Gland Leakoff	+37,503		
Reheat Steam Flow	5,042,507		
Valve Stem Leakoff	+0		
IP Cooling Leakoff	+17,755		
Steam Flow at IP Turbine	5,060,262	521.025	9,712.13
No. 6 Extraction Flow	-234,825		
Steam Flow Following Extraction	4,825,437	231.645	20,831.17
No. 5 Extraction Flow	-268,869		
BFPT Extraction Flow	-255,092		
No. 8 Gland Leakoff	-2,621		
No. 9 Gland Leakoff	-2,646		
Crossover Steam Flow	4,296,209	121.608	35,328.3
No. 4 Extraction Flow	-142,165		
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Test Relationship	W-lb <sub>m</sub> /h	P-psia	W/P
Steam Flow Following Extraction No. 3 Extraction Flow	4,154,044 -279,883	64.575	64,329
Steam Flow Following Extraction No. 2 Extraction Flow	3,874,161 -142,805	39.325	98,516
Steam Flow Following Extraction No. 1 Extraction Flow	3,731,356 -123,290	11.519	323,931
Steam Flow to Condenser	3,608,066	4.943	729,934

With the high-pressure turbine exhaust pressure kept constant, new stage flows are calculated for the turbine and the flow at each stage is divided by the test flow/stage pressure ratio to find new extraction pressures. If these new extraction pressures vary by more than 1 percent from the previous extraction pressures, stage flows and stage extraction pressures are iterated until the difference in extraction pressures on all heaters between two successive iterations is less than 1 percent.

Iterated Stage Flows	Flow, lb <sub>m</sub> /h	
	First Iteration	Second Iteration
Throttle Flow	6,221,229	6,221,229
Valve Stem Leakoff	935	935
IP Cooling Leakoff	17,755	17,755
No. 3 Gland Leakoff	37,503	37,503
No. 8 Extraction Flow	589,765	588,760
Steam Flow Following Extraction	5,575,271	5,576,276
No. 4 Gland Leakoff	6,345	6,345
No. 5 Gland Leakoff	3,916	3,916
No. 6 Gland Leakoff	10,088	10,088
No. 7 Gland Leakoff	4,634	4,634
No. 7 Extraction Flow	563,230	564,540
No. 3 Leakoff Flow	37,503	37,503

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<u>Iterated Stage Flows</u>	<u>Flow, lb<sub>m</sub>/h</u>	
	<u>First Iteration</u>	<u>Second Iteration</u>
Reheat Steam Flow	5,024,561	5,024,256
Valve Stem Leakoff	0	0
IP Cooling Leakoff	17,755	17,755
Steam Flow at IP Turbine	5,042,316	5,042,011
No. 6 Extraction Flow	229,485	231,590
Steam Flow Following Extraction	4,812,831	4,810,421
No. 5 Extraction Flow	255,560	255,035
BFPT Extraction Flow	294,815	294,815
No. 8 Gland Leakoff	2,621	2,621
No. 9 Gland Leakoff	2,646	2,646
Crossover Steam Flow	4,257,189	4,255,304
No. 4 Extraction Flow	139,680	139,360
Steam Flow Following Extraction	4,117,509	4,115,944
No. 3 Extraction Flow	278,500	278,515
Steam Flow Following Extraction	3,839,009	3,837,429
No. 2 Extraction Flow	156,270	155,395
Steam Flow Following Extraction	3,682,739	3,682,034
No. 1 Extraction Flow	112,660	110,795
Steam Flow to Condenser	3,570,079	3,571,239

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<u>Iterated Stage Pressures, psia</u>	<u>Test</u>	<u>First Iteration</u>	<u>Second Iteration</u>
Stage 4	1075.375	1,074.356	1,074.549
Hot Reheat	521.025	519.177	519.146
Stage 11	231.645	231.040	230.924
Stage 14	121.608	120.504	120.450
Stage 15	64.575	64.007	63.983
Stage 16	39.325	38.968	38.952
Stage 18	11.519	11.369	11.367
Stage 19	4.943	4.891	4.893

A new corrected generator load is calculated by performing a heat balance around the turbine using the new turbine flows. Electrical and mechanical losses in the generator are subtracted to find the corrected generator load.

The heat rate is then calculated using the new reheat flow and hot reheat enthalpy, condensate flow, and the specified enthalpy rise across the condensate and booster boiler feed pumps.

$$\text{Heat Rate} = \frac{\text{QINPUT}}{\text{QGEN}}$$

QGEN = Corrected Generator Load

QINPUT = FMS (HMS-HFW08) + FFW (DHBBFP) + FCND (DHCNDP)  
+ FRHS (HHRH - HCRH) + 0.001 FFW (HDRUM - HFW08)

DHCNDP = Specified Enthalpy Rise Across Condensate Pump

DHBBFP = Specified Enthalpy Rise Across Booster Boiler Feed Pump

Test 6 Group I Corrected Heat Rate

$$\begin{aligned}
 &= [6,221,229 (1,458.48 - 548.25) + 6,283,440 (1.45) + \\
 &\quad 4,627,080 (1.48) + 5,024,256 (1,521.95 - 1,304.12)] / 854,450.2 \\
 &= 7,928.4 \text{ Btu/kWh}
 \end{aligned}$$

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Group II corrections are then applied to the heat rate and load for nonspecified turbine steam conditions as follows.

	<u>Heat Rate</u>	<u>Load</u>
Initial Throttle Pressure	1.0005	0.9920
Initial Throttle Temperature	1.0008	1.0005
Reheater Pressure Drop	0.9977	1.0060
Exhaust Pressure	1.02134	0.9791
Hot Reheat Steam Temperature	0.9996	1.0015

$$\text{Corrected Heat Rate} = \frac{\text{Corrected Heat Rate (Group I)}}{\text{Total Group II Heat Rate Corrections}}$$

$$\text{Corrected Load} = \frac{\text{Corrected Load (Group I)}}{\text{Total Group II Load Corrections}}$$

$$\text{Total Group II Heat Rate Corrections} = 1.01991$$

$$\text{Total Group II Load Corrections} = 0.9790$$

$$\text{Corrected Heat Rate} = 7773.6 \text{ Btu/kWh}$$

$$\text{Corrected Load} = 872,779 \text{ kW}$$

#### CALCULATION OF FEEDWATER HEATER PERFORMANCE

TD = Terminal Temperature Difference  
= TSAT - TFWI

TSAT = Saturation Temperature of Extraction Steam at Test Pressure

TFWO = Temperature of Feedwater out of Heater

SA = Subcooler Approach Temperature  
= TDR - TFWI

TDR = Feedwater Heater Drain Temperature

TFWI = Temperature of Feedwater into Heater

TD8A = 0.42 F

SA8A = 7.18 F

TD8B = -0.74 F

SA8B = 7.22 F

TD7A = -0.98 F

SA7A = 9.25 F

TD7B = -0.15 F

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SA7B = 8.26 F  
 TD6A = -1.33 F  
 SA6A = 7.51 F  
 TD6B = -1.22 F  
 SA6B = 8.03 F  
 TD5 = -0.14 F  
 TD4 = -0.28 F  
 SA4 = 4.79 F  
 TD3 = -0.01 F  
 SA3 = 8.74 F  
 TD2 = 2.13 F  
 SA2 = 7.90 F  
 TD1A = 0.29 F  
 TD1B = 0.25 F  
 TD1C = 5.35 F  
 SA1 = 5.45 F

#### CALCULATION OF BOILER FEED PUMP PERFORMANCE

FFWBFPA = Flow Feedwater Boiler Feed Pump A (Station Data) = 2,970,960 lb<sub>m</sub>/h

DH = Developed Head

VF = Volumetric Flow

CVF = Corrected Volumetric Flow

CDH = Corrected Developed Head

EDH = Expected Developed Head

RP = Relative Performance

SG = Specific Gravity of Water Pumped

EFFBFPA = Boiler Feed Pump A Efficiency

EFFBFPA =  $VF \times DH \times SG \times 100 \times 8.33 / (33,000 \times \text{HPBFPTA})$

VFWPA = Average Specific Volume Water Pumped

DH =  $[(VFWPDA \times \text{PFWPD}) - (VFWPIA \times \text{PFWPI})] \times 144 \text{ in.}^2/\text{ft}^2$

DH = 6,624.2 ft

VF =  $\text{FFWBFPA} \times \text{VFWPA} \times 7.4805/60$

VF = 6,584.6 gpm

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CVF =  $VF \times 5,700 \text{ rpm/SPBFPTA}$

CVF = 7,153.6 gpm

CDH =  $DH \times (5750)^2 / \text{SPBFPTA}^2$

CDH = 7,818.5 ft

EDH =  $f(\text{CVF})$

= 8,562.8 ft

RP =  $DH / \text{EDH}$

RP = 0.774

SG =  $0.01605 / \text{VFWPA}$

SG = 0.90286

EFFBFPA = 80.51 percent

#### CONDENSER PERFORMANCE

FSCND = Flow of Steam to Condenser = 3,608,066 lb<sub>m</sub>/h

TSATA = Temperature of Saturated Water in HP Condenser A = 127.06 F

TSATB = Temperature of Saturated Water in IP Condenser B = 125.67 F

TSATC = Temperature of Saturated Water in LP Condenser C = 109.75 F

#### Correction Factors for Off-Design Circulating Water

Inlet Temperature - (Refer to Standards of the Heat Exchange Institute in Section 6.0)

HTCFA = Heat Transfer Coefficient Correction for HP Condenser A = 1.101

HTCFB = Heat Transfer Coefficient Correction for IP Condenser B = 1.065

HTCFC = Heat Transfer Coefficient Correction for LP Condenser C = 1.065

#### Log Mean Temperature Difference

TLMDC =  $(\text{TCWO} - \text{TCWI}) / \ln[(\text{TSAT} - \text{TCWI}) / (\text{TSAT} - \text{TCWO})]$

TLMDCA = 16.36 F

TLMDCB = 20.90 F

TLMDCC = 15.22 F

#### Terminal Temperature Difference

$$TTD = TSAT - TCWO$$

$$TTDA = 9.16 \text{ F}$$

$$TTDB = 9.45 \text{ F}$$

$$TTDC = 9.30 \text{ F}$$

$$FCNDC = \text{Flow to Condenser C} = FSCND/3 + FSBFPTB + FEXT4 + FEXT3 + FEXT2 + FEXT1A + FEXT1B + FEXT1C + FDV1A$$

$$FCNDC = 2,024,660 \text{ lb}_m/\text{h}$$

$$FCNDB = \text{Flow to Condenser B} = FSCND/3 + FCNDC$$

$$FCNDB = 3,227,349 \text{ lb}_m/\text{h}$$

$$FCNDA = \text{Flow to Condenser A} = FSCND/3 + FCNDB + FSBFPTA + FDVCND$$

$$FCNDA = 4,558,968 \text{ lb}_m/\text{h}$$

#### Individual Used Energy End Point of Each Condenser

$$UEEPA = 1,047.71 \text{ Btu/lb}_m$$

$$UEEPB = 1,045.29 \text{ Btu/lb}_m$$

$$UEEPC = 1,024.87 \text{ Btu/lb}_m$$

$$QCND = \text{Heat Transferred to Circulating Water in Condenser}$$

$$QCNDA = 1,269,487,071 \text{ Btu/h}$$

$$QCNDB = 1,112,344,039 \text{ Btu/h}$$

$$QCNDC = 1,285,791,473 \text{ Btu/h}$$

#### Calculated Heat Transfer Coefficient

$$UC = QCND / (\text{Area of Condenser} \times TLMDC)$$

$$AREA = 150,000 \text{ ft}^2$$

$$UCA = 517.31 \text{ Btu/h} - \text{ft}^2 - \text{F}$$

$$UCB = 354.81 \text{ Btu/h} - \text{ft}^2 - \text{F}$$

$$UCC = 563.20 \text{ Btu/h} - \text{ft}^2 - \text{F}$$

#### Corrected Heat Transfer Coefficient

$$UCXC = UC \times TCPCW$$

$$UCAC = 569.56 \text{ Btu/h} - \text{ft}^2 - \text{F}$$

$$UCBC = 377.88 \text{ Btu/h} - \text{ft}^2 - \text{F}$$

$$UCCC = 599.81 \text{ Btu/h} - \text{ft}^2 - \text{F}$$

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Cleanliness Factor

$$CFC = 100 \times UCXC/UDCX$$

UDCX = Minimum Cleanliness Heat Transfer Coefficient

$$CFCA = 569.56 \times 100/603.13 = 94.43 \text{ percent}$$

$$CFCB = 377.88 \times 100/604.26 = 62.54 \text{ percent}$$

$$CFCC = 599.81 \times 100/604.26 = 99.26 \text{ percent}$$

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## 6.0 REFERENCES

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- "ASME Steam Tables"; American Society of Mechanical Engineers - Fourth Edition, New York, 1979.
- "Steam Turbines, PTC 6.0"; American Society of Mechanical Engineers, New York, 1976.
- "Steam Turbines, PTC 6.0, Appendix A"; American Society of Mechanical Engineers, New York, 1982.
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- "Performance Test Report, Unit 1, Volume 1, Turbine Cycle", Black & Veatch, Kansas City, 1987.

## ELECTRICAL LOAD CALCULATION

- 1) SECONDARY WATTS = ( COUNTS \* 0.3 ) / ( TIME(hr) \* 6.0 )
- 2) CORR'D VOLTS = READING \* 120./CFVOLTS
  - A PHASE ; CFVOLTS = 119.80
  - B PHASE ; CFVOLTS = 119.94
  - C PHASE ; CFVOLTS = 119.77
- 3) CORR'D AMPS = READING \* 0.1/CFAMPS
  - A PHASE ; CFAMPS = .09982
  - B PHASE ; CFAMPS = .09991
  - C PHASE ; CFAMPS = .09996
- 4) POWER FACTOR (PF) = [1]/([2]\*[3])
- 5) WATTHOUR METER CALIBRATION FOR TEST VALUE OF [CORR'D AMPS] AND [POWER FACTOR] AND [CORR'D VOLTS]
- 6) CORR'D POWER FACTOR = [4] \* [5]
- 7) CORR'D SECONDARY WATTS = [1] \* [5]
- 8) PT RATIO = 115.0
- 9) PT CALIBRATION = 

0.9986	A PHASE
0.9986	B PHASE
0.9983	C PHASE
- 10) CT RATIO = 5000
- 11) CT CALIBRATION = 

1.0000	A PHASE
1.0000	B PHASE
1.0000	C PHASE
- 12) KW = [7] \* [8] \* [9] \* [10] \* [11] /1000.
- 13) TOTAL KW = KW (A PHASE) + KW (B PHASE) + (C PHASE)
- 14) AVG. (PF) = [PF (A PHASE) + PF (B PHASE) + PF (C PHASE)]/3



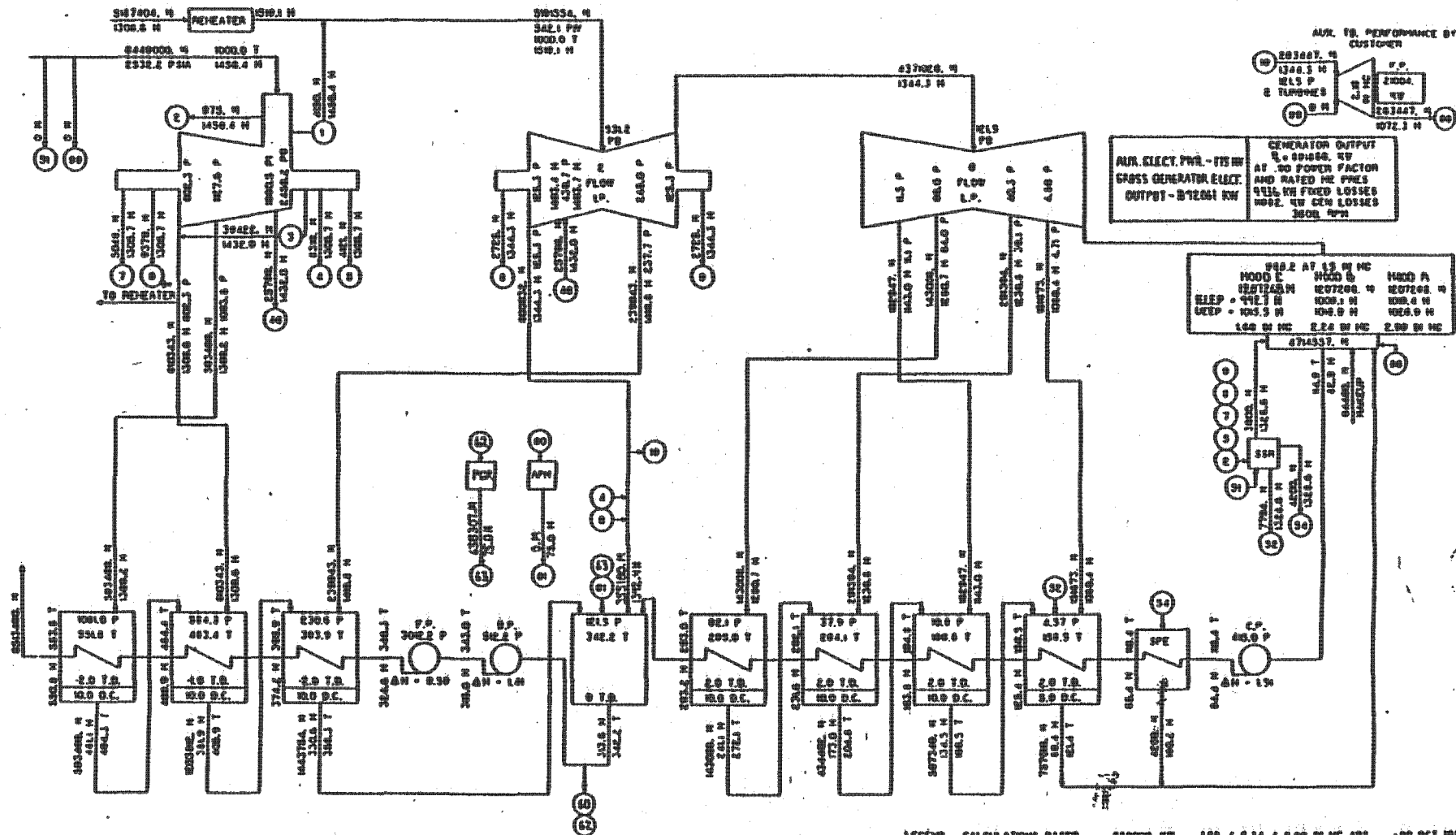
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W. K.

EXTRACTION ARRANGEMENT IS SCHEMATIC ONLY

CALCULATED DATA - NOT GUARANTEED

RATING FLOW IS 503M<sup>3</sup>/H AT INLET STEAM CONDITIONS OF 2402.2 PSIA AND 1000.0 T  
TO ASSURE THAT THE TURBINE WILL PASS THIS FLOW, CONSIDERING VARIATIONS IN FLOW COEFFICIENTS  
FROM EXPECTED VALUES, SHOP TOLERANCES ON GRADING AREAS, ETC. WHICH MAY AFFECT THE FLOW, THE  
TURBINE IS BEING DESIGNED FOR A DESIGN FLOW RATING FLOW PLUS 5.0 PERCENT OF 512730.4  
THE EQUIVALENT DESIGN FLOW AT 2532.2 PSIA AND 1000.0 T IS 514600.0 H



CUSTOMER DEFINED VALVE BEST POINT NET HEAT RATE 891006 IN 7793

LEGEND CALCULATIONS BASED ON FIRST ASME STEAM TABLES  
M<sup>3</sup> FLOW-LS/H  
P PRESSURE-PSIA  
T TEMPERATURE-F DEGREES

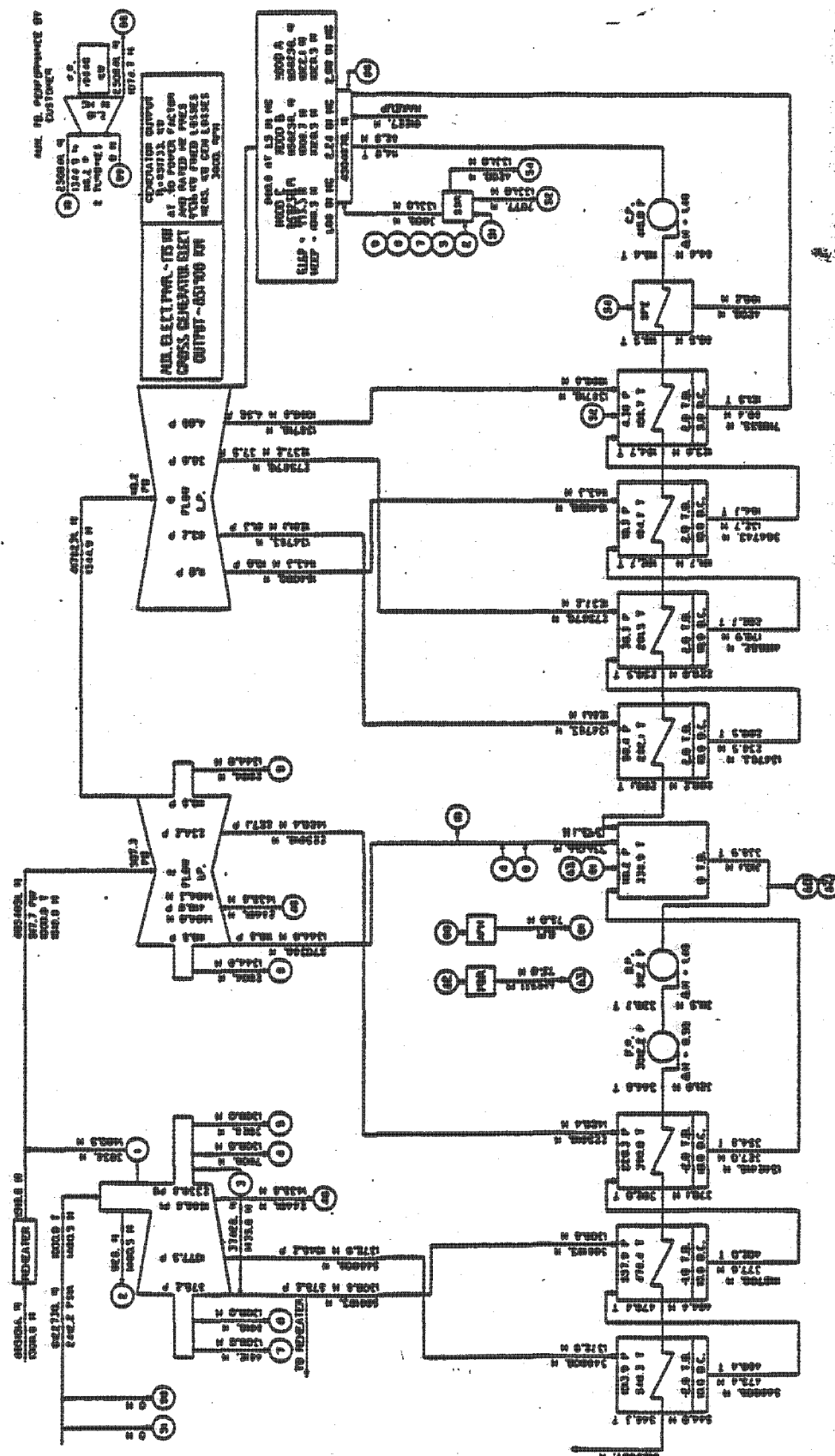
8000KW 4W 1.00 / 2.24 / 2.90 MW ABS. 1.00 PCT MW  
TCOR 30.0 DL LSS 3400 RPM  
2400 PSIA 1000 / 1000 T  
CEN 900000 4VA 90 PF LB

K. K. K.

03101 100000 0 0 0

EXTRACTION ARRANGEMENT IS SCHEMATIC ONLY

NOTES: 1. ALL DATA ARE BASED ON 100% EFFICIENCY OF ALL COMPONENTS AND ARE NOT TO BE USED FOR DESIGN PURPOSES. 2. ALL DATA ARE BASED ON 100% EFFICIENCY OF ALL COMPONENTS AND ARE NOT TO BE USED FOR DESIGN PURPOSES. 3. ALL DATA ARE BASED ON 100% EFFICIENCY OF ALL COMPONENTS AND ARE NOT TO BE USED FOR DESIGN PURPOSES.

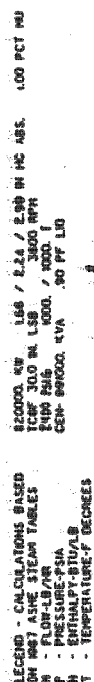


NOTES: 1. ALL DATA ARE BASED ON 100% EFFICIENCY OF ALL COMPONENTS AND ARE NOT TO BE USED FOR DESIGN PURPOSES. 2. ALL DATA ARE BASED ON 100% EFFICIENCY OF ALL COMPONENTS AND ARE NOT TO BE USED FOR DESIGN PURPOSES. 3. ALL DATA ARE BASED ON 100% EFFICIENCY OF ALL COMPONENTS AND ARE NOT TO BE USED FOR DESIGN PURPOSES.

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GENERAL ELECTRIC COMPANY, SCHEMATIC REF.



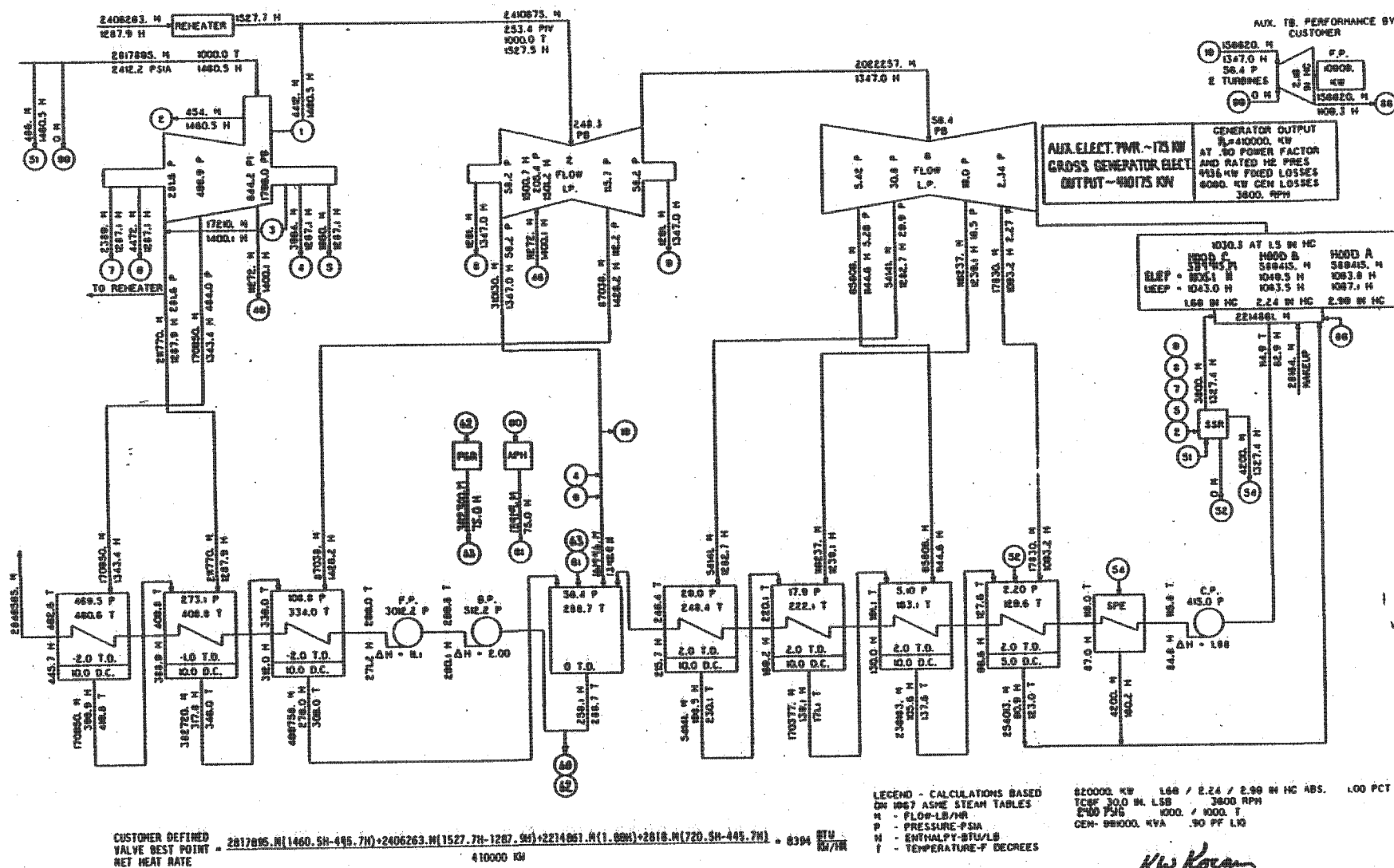
CUSTOMER DEFINED  
= 118001.M1460.5M-491.6M+3489314.M1524.3M-3290.5M+2303524.M1.56M+1180.M120.5M-491.6M  
NET WEIGHT  
BEST DATE 615000 MJ 1934 MJ/YR

ke ke

334AT 1 DEC 29 66 20 13 7-17-61

GENERAL ELECTRIC COMPANY, SCHENECTOY, N. Y.

9-17-01



GENERAL ELECTRIC COMPANY, SCHENECTADY N.Y.

534AT 1 DROZB 4802 0 14  
481 HB 147

7-17-81

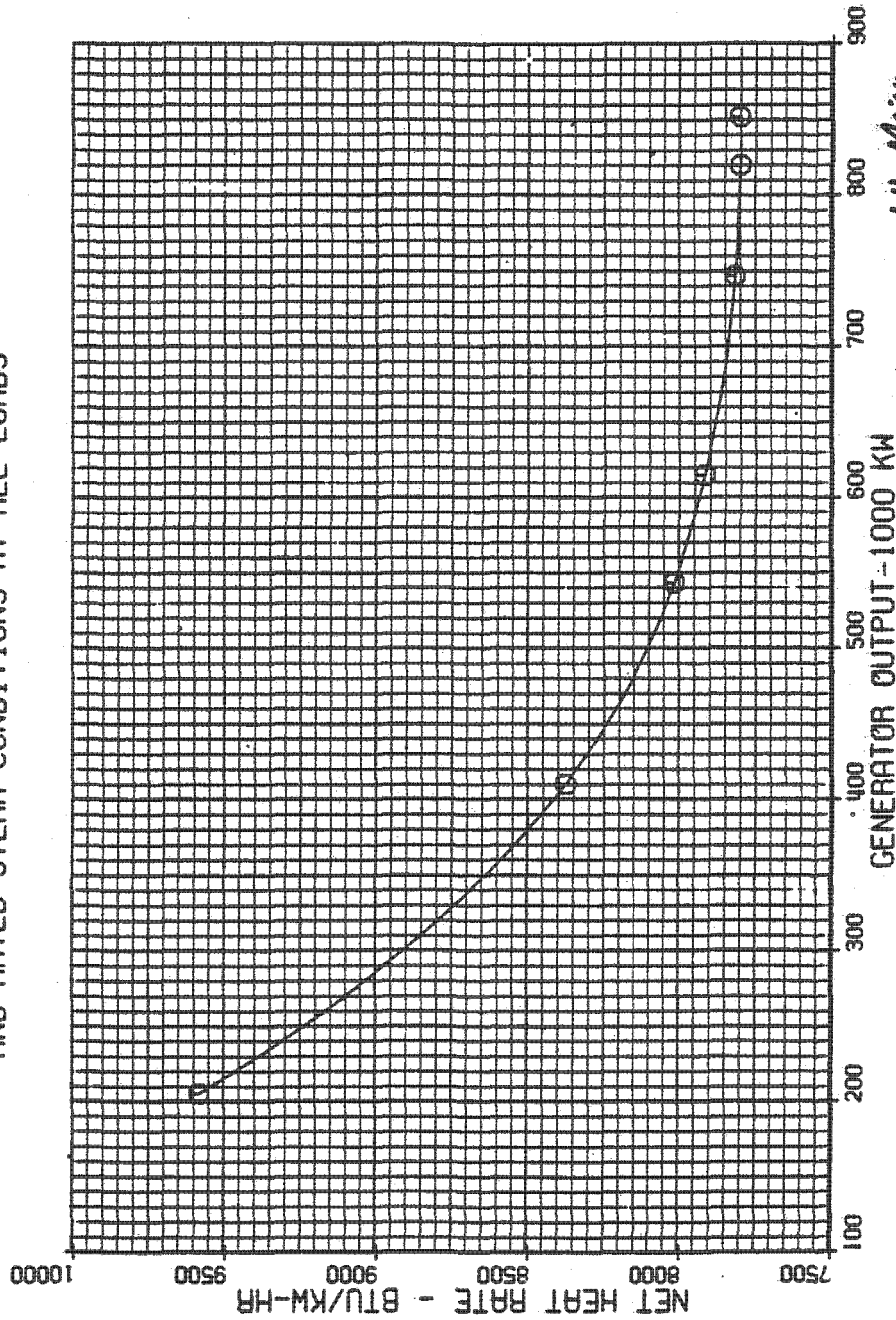


# NET HEAT RATE CURVE

820000 KW 1.66/2.24/2.99 IN HG ABS. 1.0 PCT MU  
 TCGF 30.0 IN LSB 3600 RPM  
 2400 PSIG 1000./1000. T

THESE HEAT RATES ARE BASED ON NORMAL EXTRACTION OPERATION  
 AS SHOWN ON HEAT BALANCE 481 HB 111  
 DASHED PORTION OF CURVE IS AT FLOWS IN EXCESS OF RATING FLOW  
 CIRCLED POINTS REPRESENT POINTS THROUGH WHICH CURVE WAS DRAWN  
 THIS CURVE IS NOT GUARANTEED

THESE HEAT RATES ARE AT 1.66, 2.24, 2.99 IN.HG.ABS.EXH. PRESS..1 PCT MU  
 AND RATED STEAM CONDITIONS AT ALL LOADS



K.K. Magary



168 BH 25h

GENERATOR LOSSES  
991000 KVA AT 63 PSIG H2 PRESS  
CONDUCTOR COOLED 3600 RPM

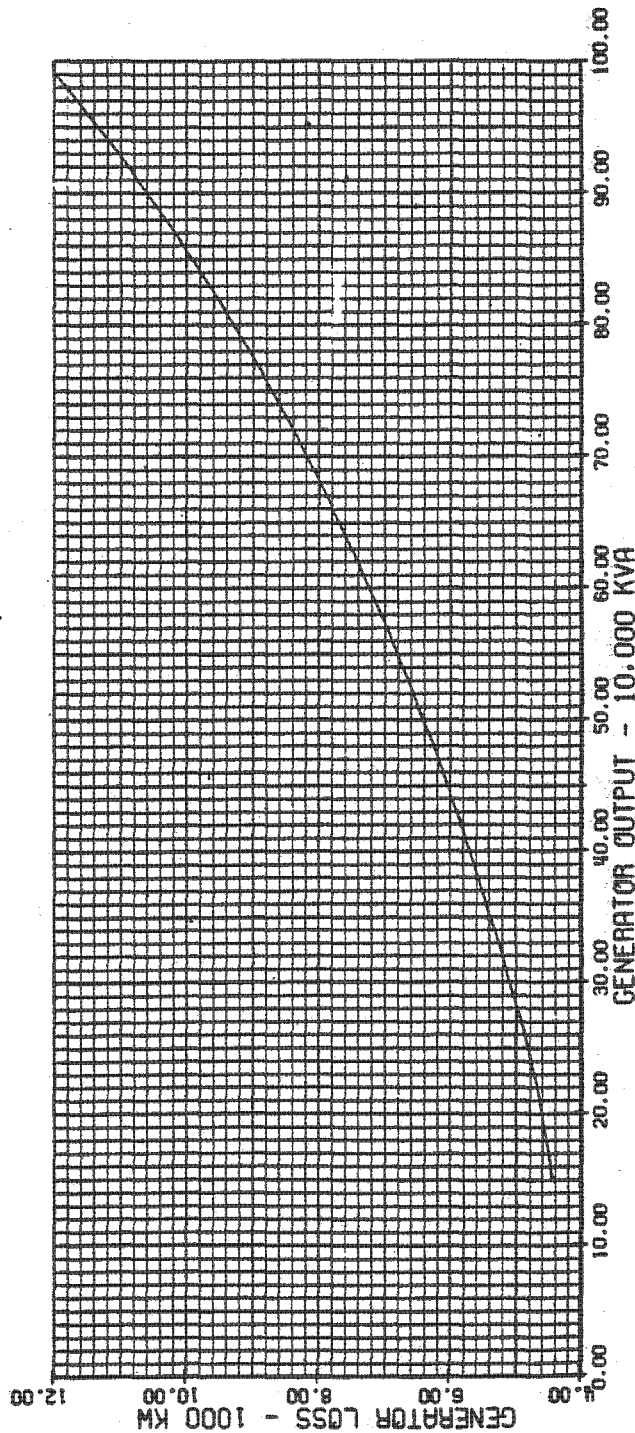
NOTES

GENERATOR LOSSES ASSUME RATED HYDROGEN PRESSURE  
AT ALL LOADS.

GENERATOR LOSS AT REDUCED HYDROGEN PRESSURE (P) =  
LOSS AT RATED HYDROGEN PRESSURE - 14.3 (P RATED - P).  
USE GENERATOR REACTIVE CAPABILITY CURVE TO DETERMINE  
GENERATOR CAPABILITY AT REDUCED HYDROGEN PRESSURE.

TURBINE GENERATOR MECHANICAL LOSSES ARE NOT INCLUDED  
IN THE GENERATOR LOSS CURVE.

IF HYDROGEN AND STATOR LIQUID COOLERS ARE LOCATED  
IN THE CONDENSATE LINE, THE LOSS TRANSFERRED TO THE  
COOLERS IS 898 KW LESS THAN THE GENERATOR  
LOSS AT ALL LOADS.



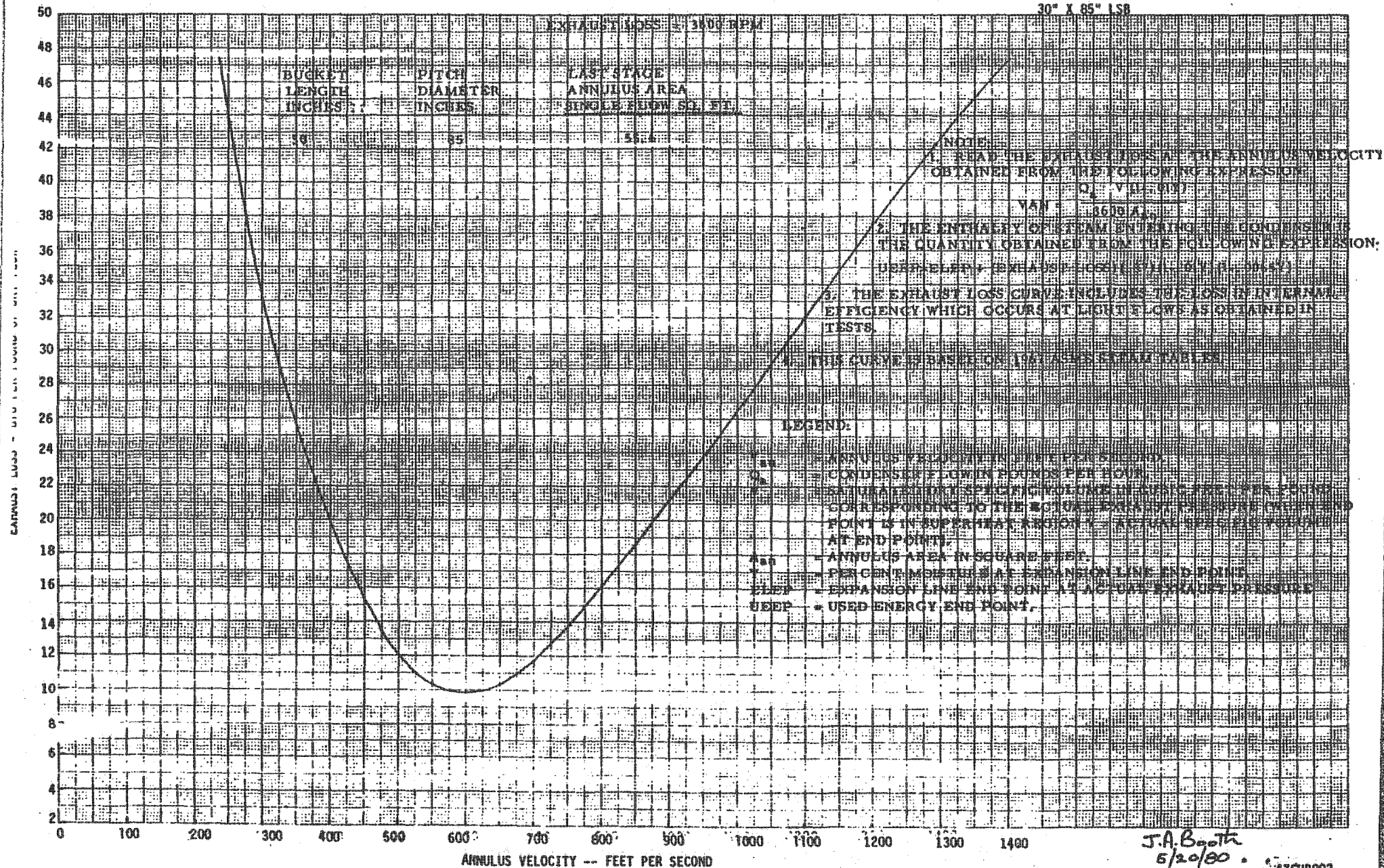
GENERAL ELECTRIC COMPANY, SCHENECTADY, NEW YORK

12/01/81

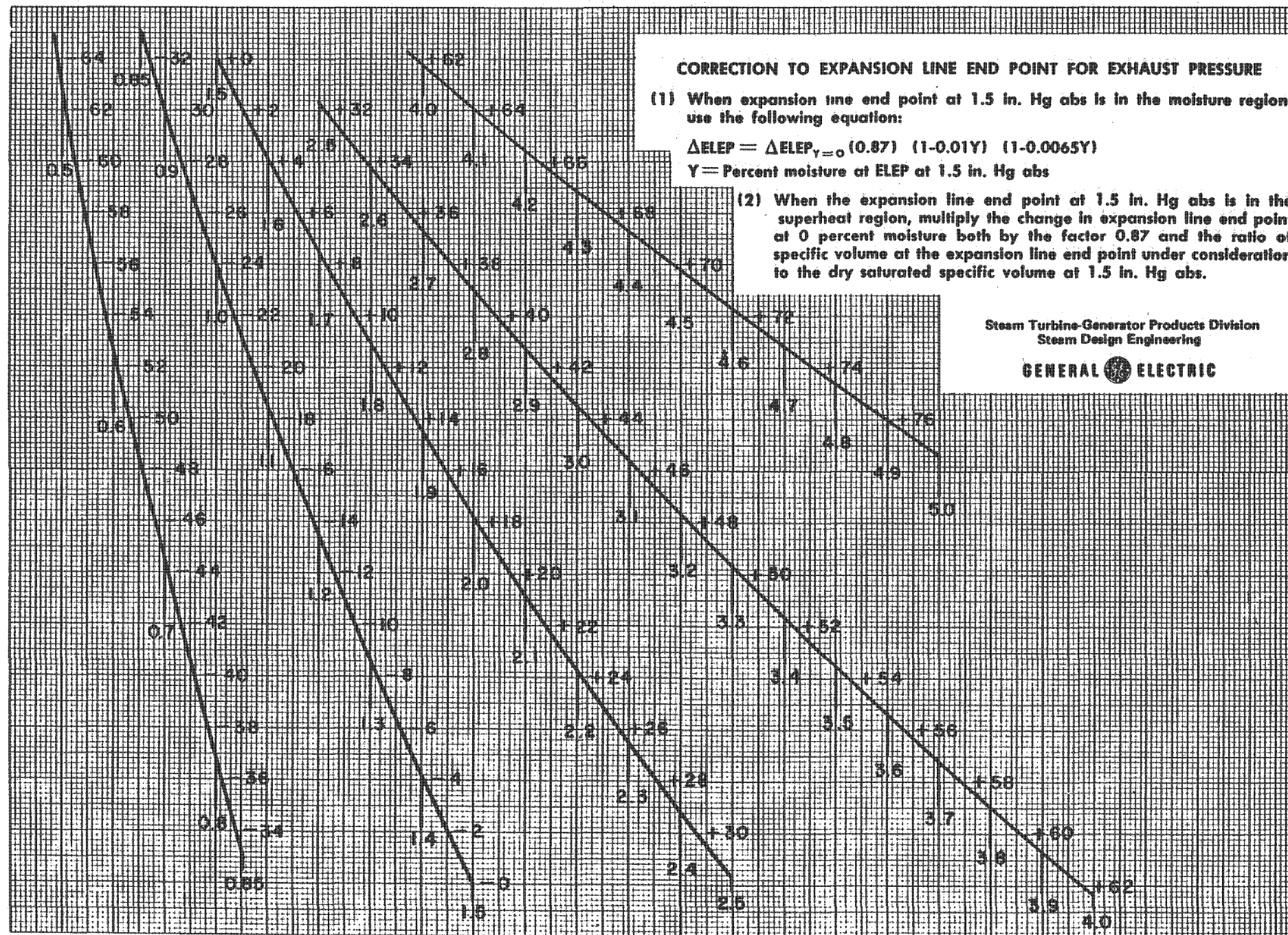
452 HB 891

*V.L. Major*





$\Delta \text{ELEP} = \Delta \text{ELEP}_{Y=0} - \Delta \text{ELEP}_{Y=0} \times \text{PERCENT MOISTURE (BTU/LB)}$

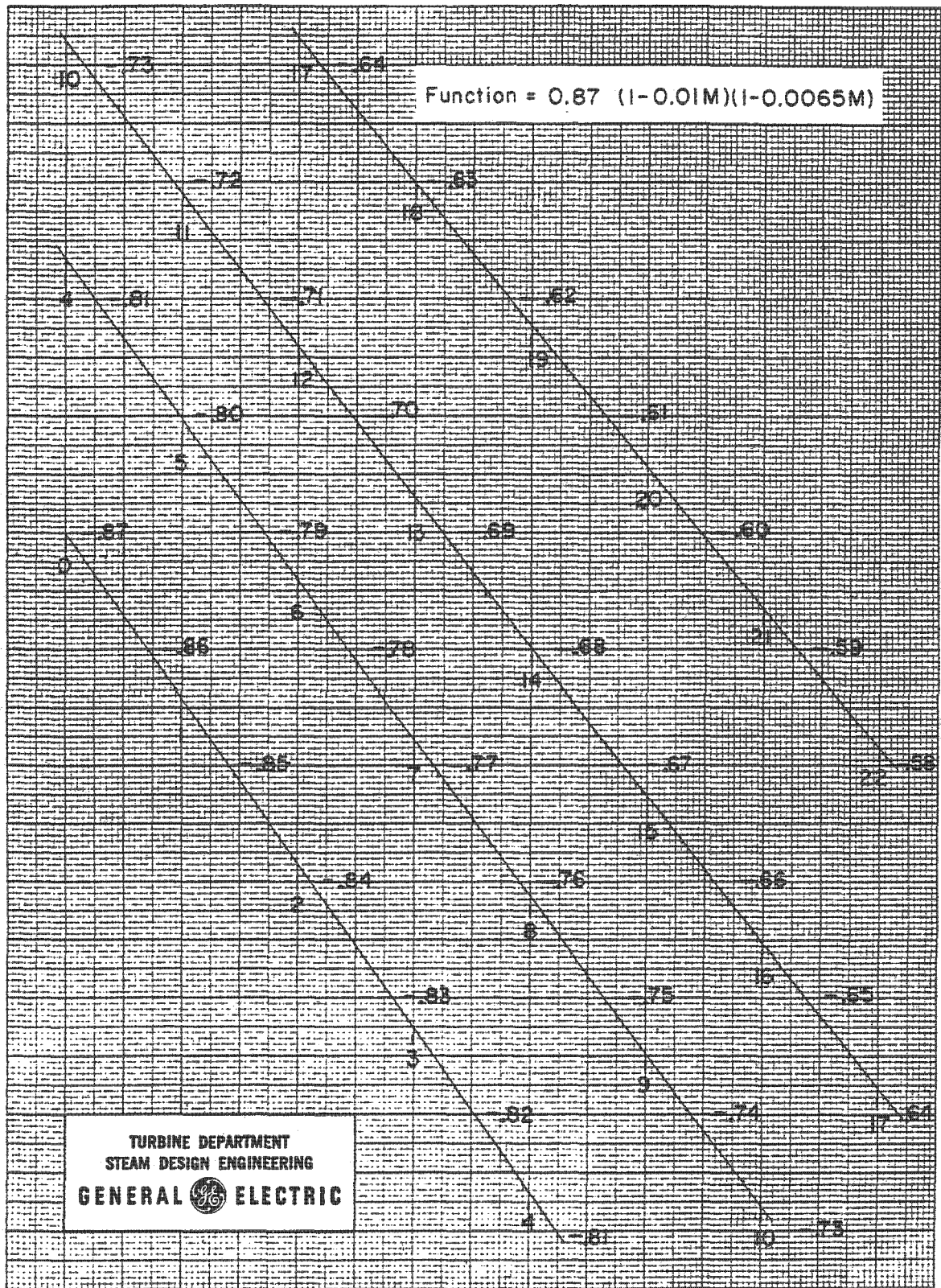


EXHAUST PRESSURE (IN. Hg ABS)

IP14\_000917



MOISTURE FUNCTION



M (% MOISTURE)

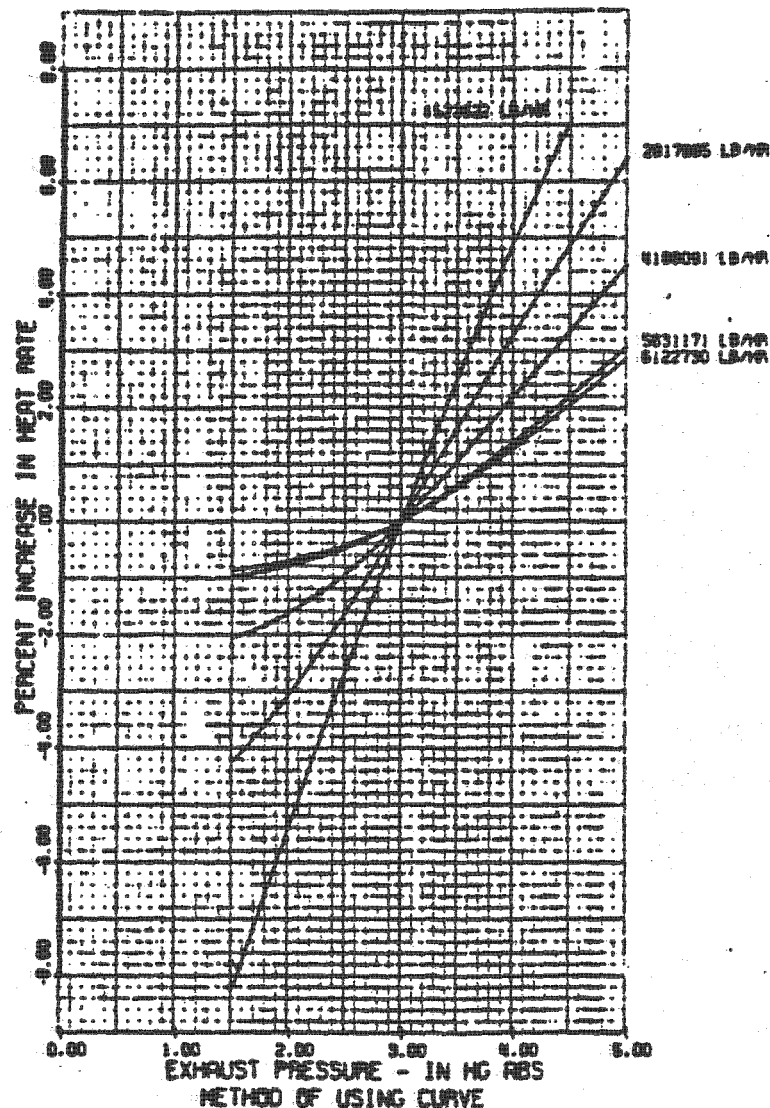
GEZ-5834

IP14\_000918

# EXHAUST PRESSURE CORRECTION FACTORS

820000 KW AT 1.66/ 2.24/ 2.99 IN HG ABS 1.00 PCT MU  
 TCSF-30.0 IN LSB 3600 RPM  
 2400 PSIA 1000/1000 T

481 HB 475



VALUES NEAR CURVES ARE FLOWS AT 2400 PSIA 1000 T  
 THESE CORRECTION FACTORS ASSUME CONSTANT CONTROL VALVE OPENING  
 APPLY CORRECTIONS TO HEAT RATE AND KW LOADS  
 AT 2.99/ 2.24/ 1.66 IN HG ABS AND 0.0 PCT MU.

THE PERCENT CHANGE IN KW LOAD FOR VARIOUS EXHAUST PRESSURES IS EQUAL TO  
 (MINUS PCT INCREASE IN HEAT RATE)100/(100 + PCT INCREASE IN HEAT RATE)

THESE CORRECTION FACTORS ARE NOT GUARANTEED

PRESSURES ALONG ABSCISSA ARE PRESSURES IN HOOD A

PRESSURE (IN HG ABS) FOR HOOD A	HOOD B	HOOD C
1.50	1.09	.78
2.00	1.47	1.07
2.50	1.85	1.36
3.00	2.24	1.66
3.50	2.63	1.96
4.00	3.03	2.27
4.50	3.42	2.58
5.00	3.82	2.89

481 HB 475

GENERAL ELECTRIC COMPANY. SCHENECTADY. NEW YORK

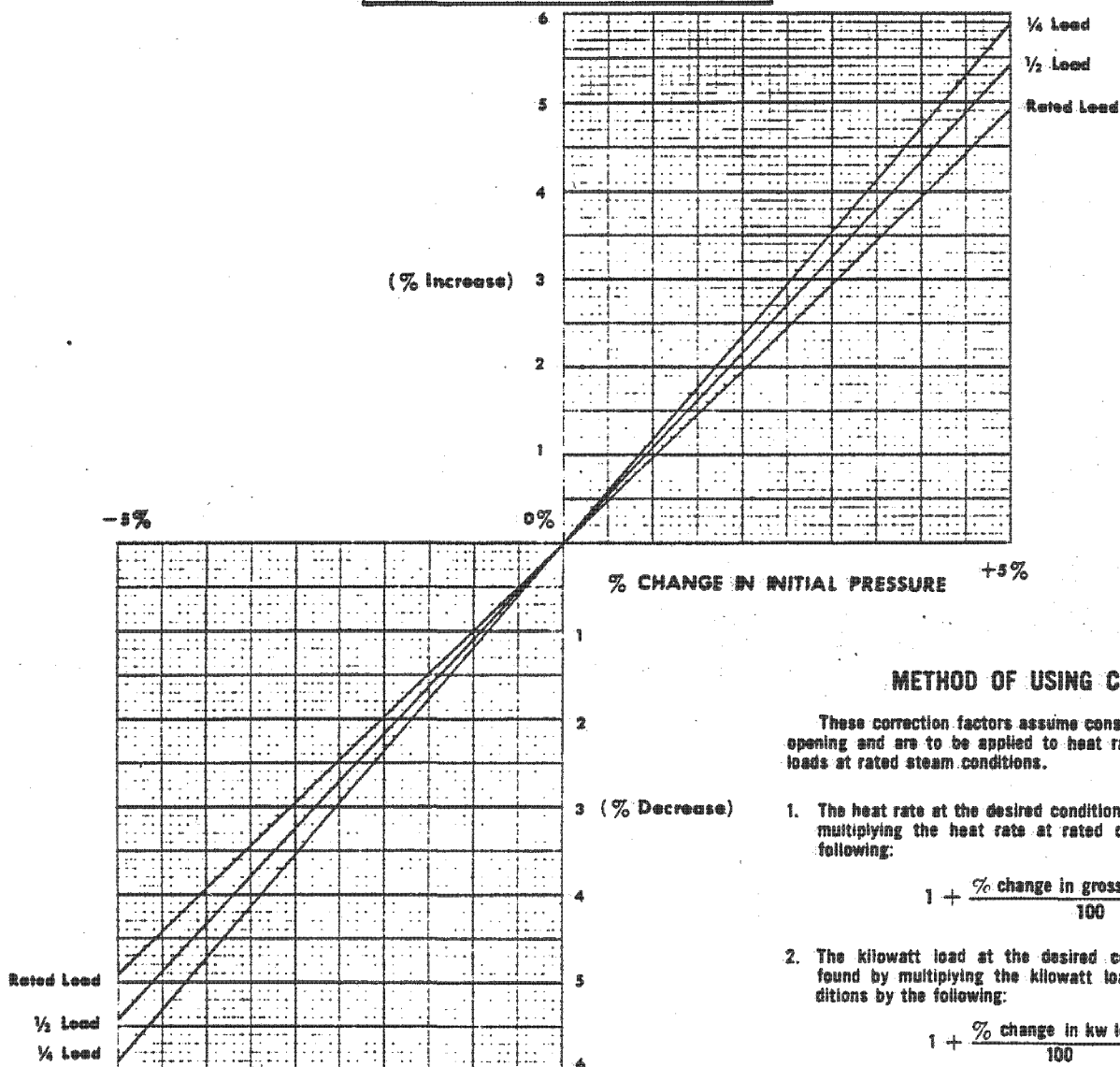
12/04/81

3/26/84 Rev.1

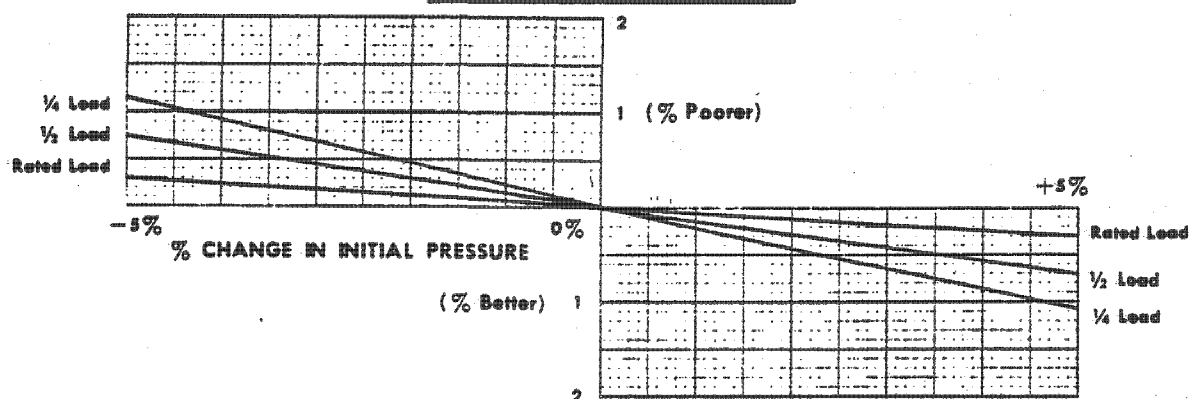
IP14\_000919

# INITIAL PRESSURE CORRECTION FACTORS FOR SINGLE REHEAT UNITS

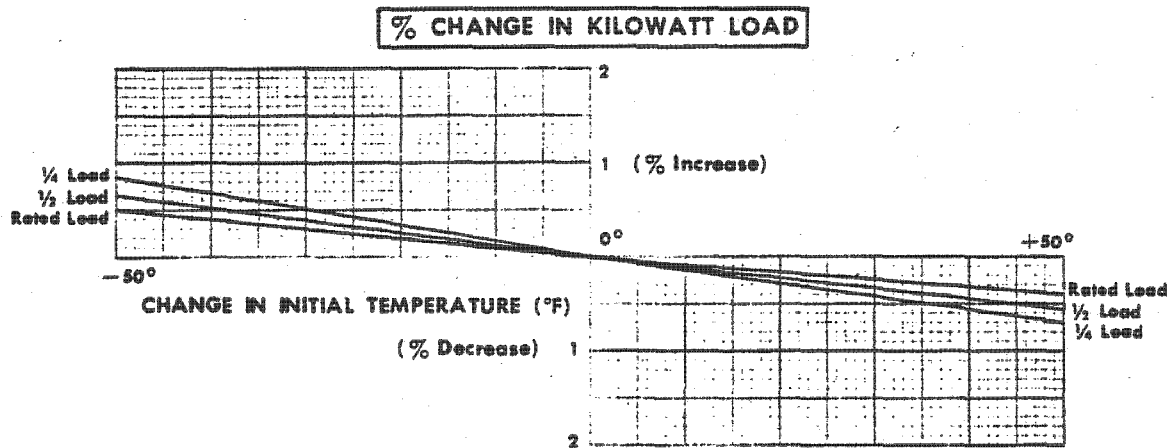
## % CHANGE IN KILOWATT LOAD



## % CHANGE IN HEAT RATE



# INITIAL TEMPERATURE CORRECTION FACTORS FOR SINGLE REHEAT—SUBCRITICAL PRESSURE UNITS



## METHOD OF USING CURVES

These correction factors assume constant control valve opening and are to be applied to heat rates and kilowatt loads at rated steam conditions.

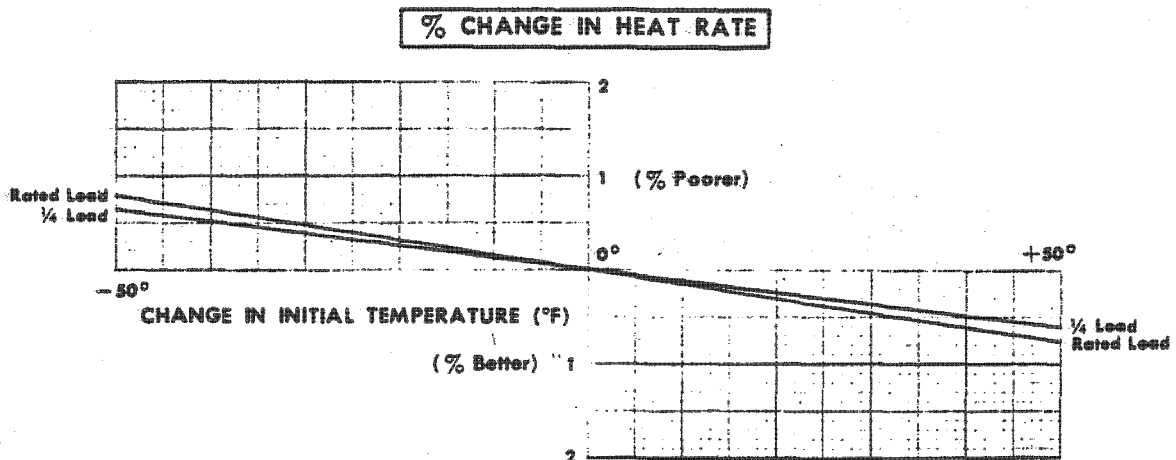
1. The heat rate at the desired condition can be found by multiplying the heat rate at rated conditions by the following:

$$1 + \frac{\% \text{ change in gross heat rate}}{100}$$

2. The kilowatt load at the desired conditions can be found by multiplying the kilowatt load at rated conditions by the following:

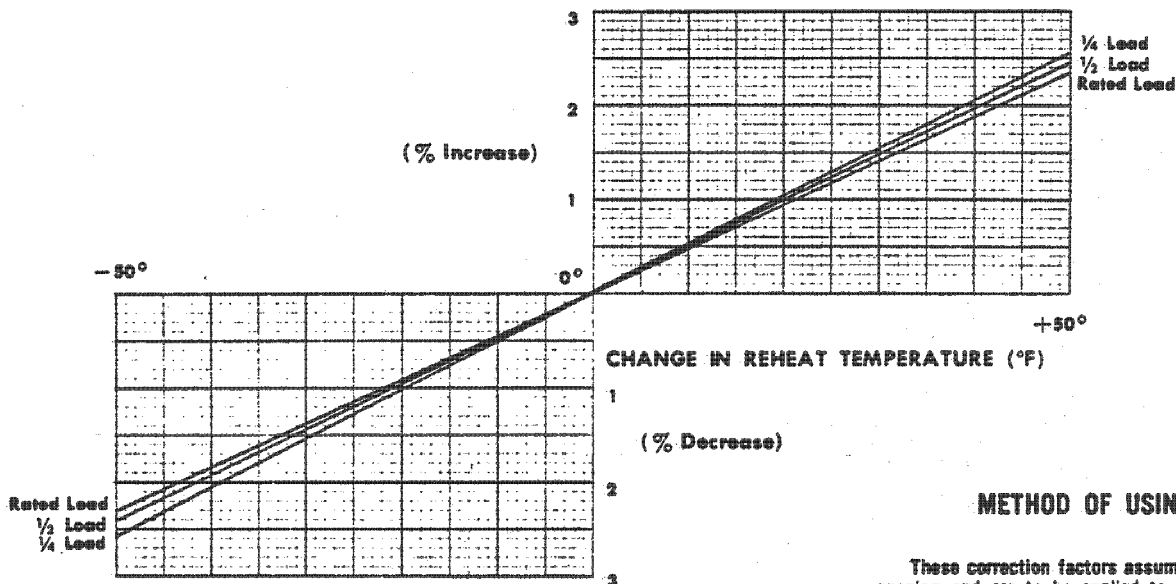
$$1 + \frac{\% \text{ change in kw load}}{100}$$

3. These correction factors are not guaranteed.



# REHEAT TEMPERATURE CORRECTION FACTORS FOR SINGLE REHEAT UNITS

## % CHANGE IN KILOWATT LOAD



## METHOD OF USING CURVES

These correction factors assume constant control valve opening and are to be applied to heat rates and kilowatt loads at rated steam conditions.

1. The heat rate at the desired condition can be found by multiplying the heat rate at rated conditions by the following:

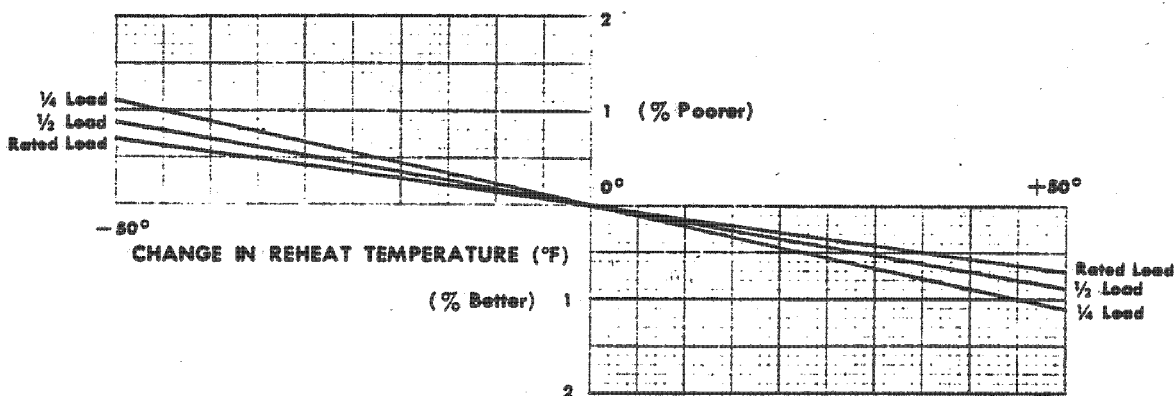
$$1 + \frac{\% \text{ change in gross heat rate}}{100}$$

2. The kilowatt load at the desired conditions can be found by multiplying the kilowatt load at rated conditions by the following:

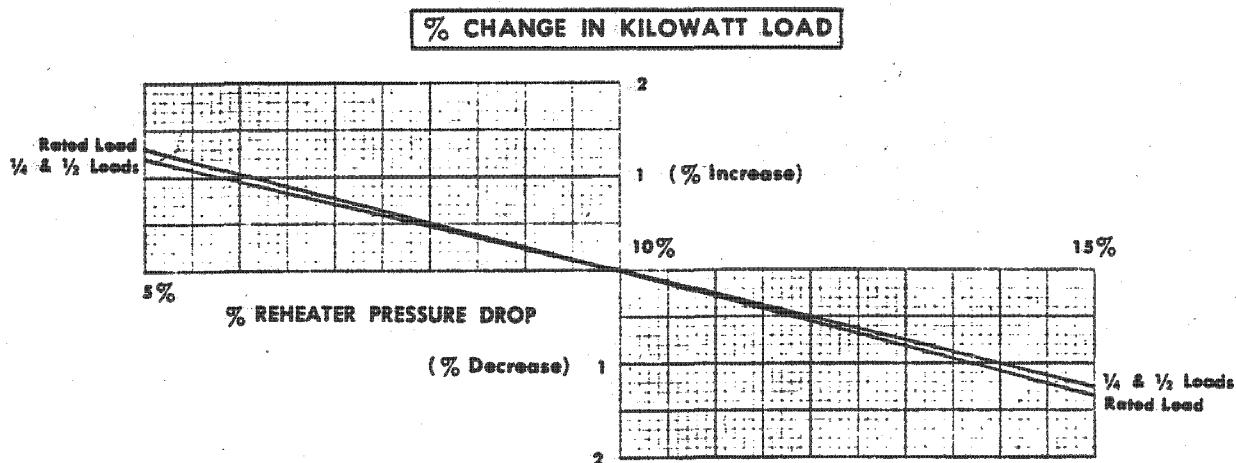
$$1 + \frac{\% \text{ change in kw load}}{100}$$

3. These correction factors are not guaranteed.

## % CHANGE IN HEAT RATE



# REHEATER PRESSURE DROP CORRECTION FACTORS FOR SINGLE REHEAT UNITS



## METHOD OF USING CURVES

These correction factors assume constant control valve opening and are to be applied to heat rates and kilowatt loads at rated steam conditions.

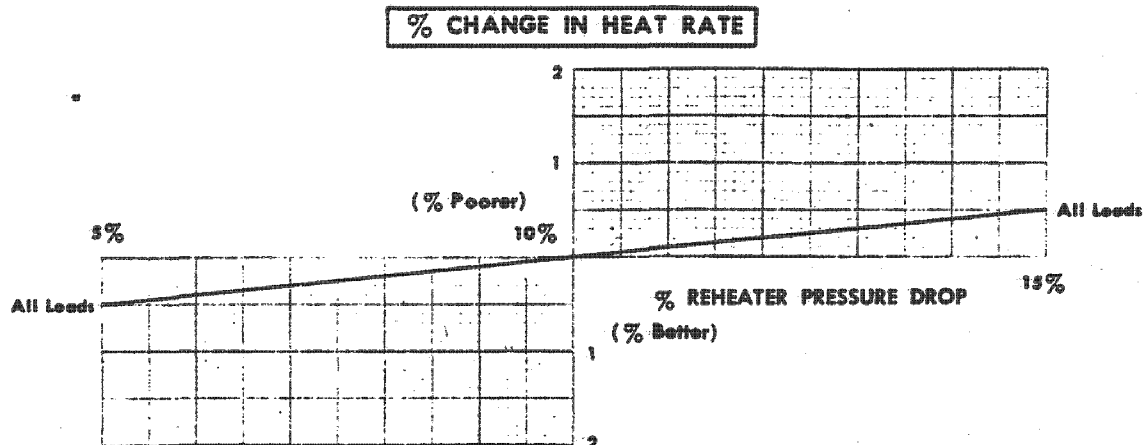
1. The heat rate at the desired condition can be found by multiplying the heat rate at rated conditions by the following:

$$1 + \frac{\% \text{ change in gross heat rate}}{100}$$

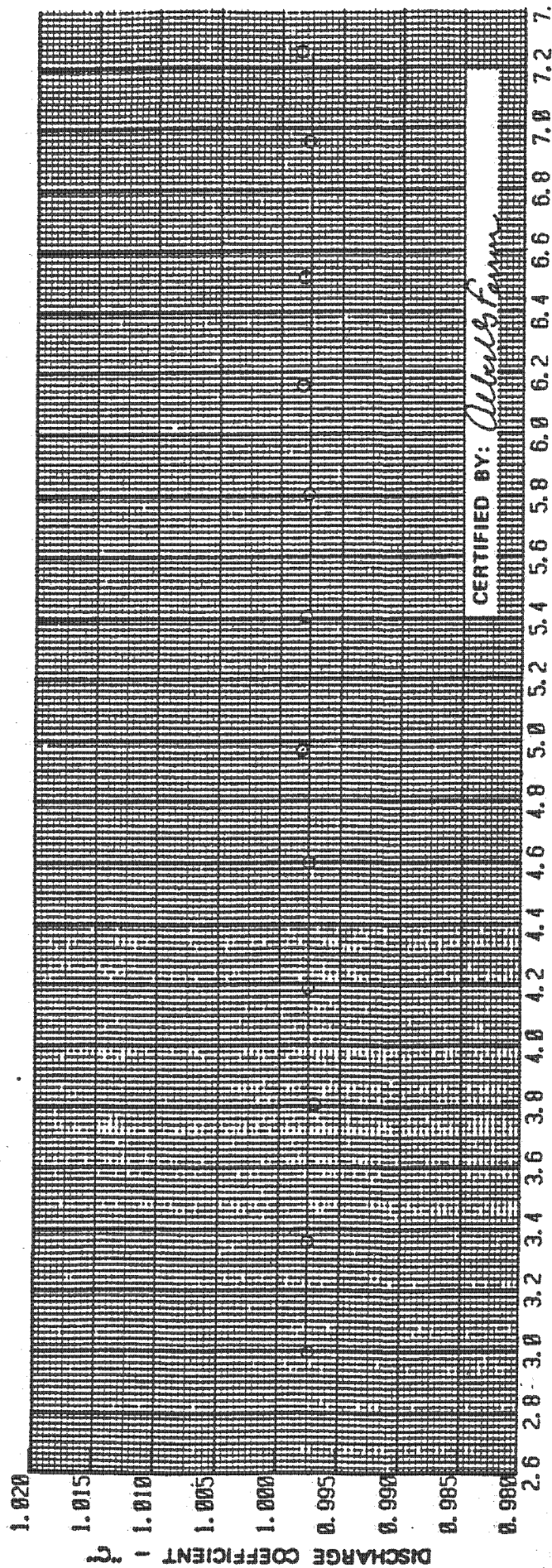
2. The kilowatt load at the desired conditions can be found by multiplying the kilowatt load at rated conditions by the following:

$$1 + \frac{\% \text{ change in kw load}}{100}$$

3. These correction factors are not guaranteed.







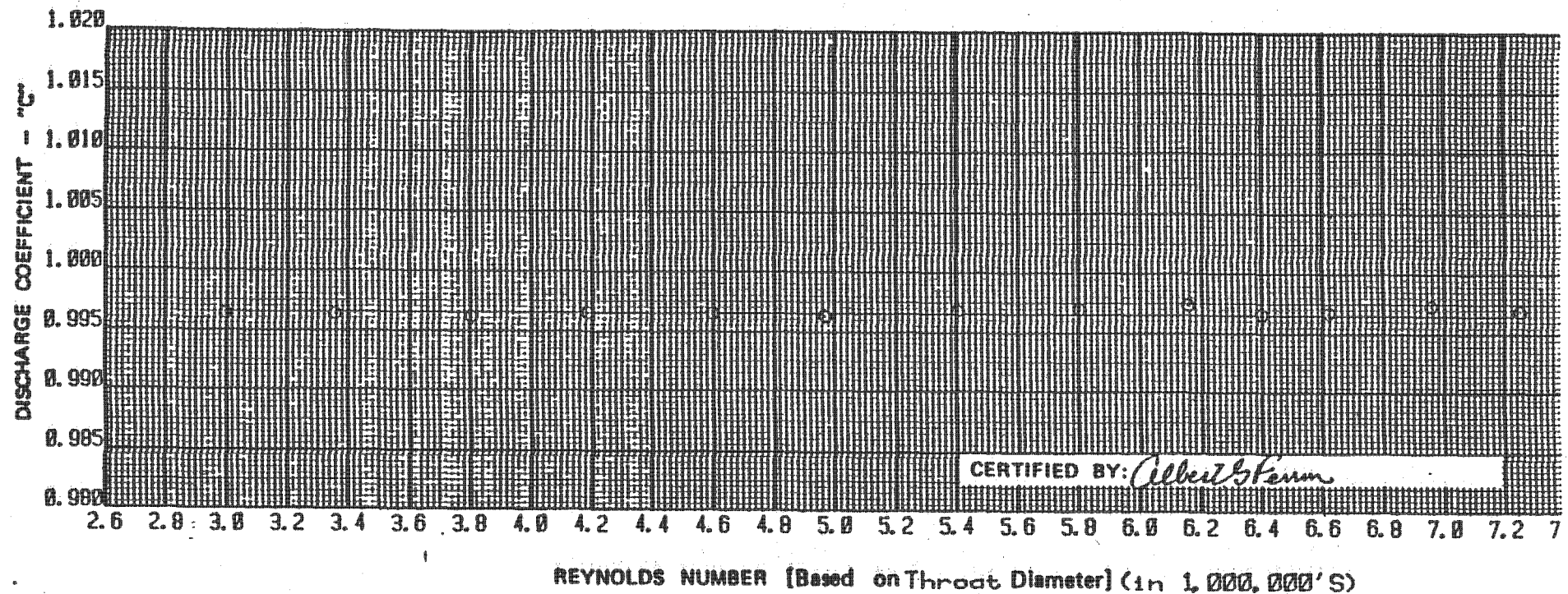
CERTIFIED BY: *J. J. Farnham*

REYNOLDS NUMBER (Based on Throat Diameter) (in 1,000,000's)

MEAN -- 0.9977 ABOVE THROAT  
REYNOLDS # 2900000

TAP SET # A  
24" FLOW NOZZLE ASSEMBLY  
TAG NUMBER: 9 FWC51-FE-0010  
DANIEL INDUSTRIES, INC.  
PO NUMBER: 77256  
OCTOBER 1, 1984

$q_a = C K_M \sqrt{h}$	
$q_a$ - Actual Flow Rate (ft <sup>3</sup> /sec)	4.3092
$C$ - Discharge Coefficient - Dimensionless	1.0005
$h$ - Pressure Differential in Feet of Water at Run Temperature	0.5283
$K_M$ - Meter Constant - $\frac{29.92 \times F_a}{\sqrt{1 - \beta^4}}$	32.163
$F_a$ - Thermal Expansion Factor -	0.4233
$a$ - Throat Area (ft <sup>2</sup> ) -	23.250
$g$ - Local Acceleration of Gravity (ft/sec <sup>2</sup> )	9.842
$\beta$ - Dimensionless Ratio of Throat to Pipe Diameter -	
Upstream Diameter -	
Throat Diameter -	
Dimensions in: DANIEL	



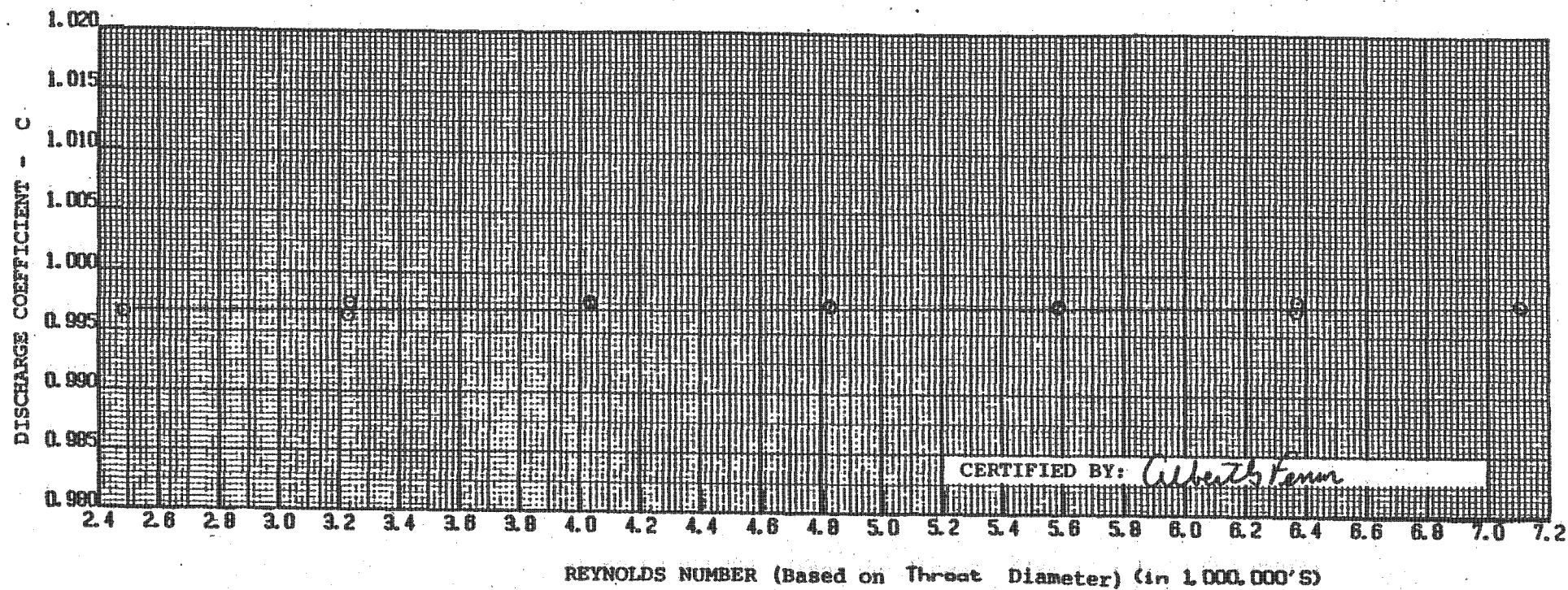
$q_a = C K_M \sqrt{h}$	
$q_a$ = Actual Flow Rate (ft <sup>3</sup> /sec)	
$C$ = Discharge Coefficient - Dimensionless	
$h$ = Pressure Differential in Feet of Water at Run Temperature	
$K_M$ = Meter Constant = $\frac{a\sqrt{2g} \times F_a}{\sqrt{1 - \beta^4}}$	4.3092
$F_a$ = Thermal Expansion Factor =	1.0005
$a$ = Throat Area (ft <sup>2</sup> ) =	0.5283
$g$ = Local Acceleration of Gravity (ft/sec <sup>2</sup> )	32.163
$\beta$ = Dimensionless Ratio of Throat to Pipe Diameter =	0.4233
Upstream Diameter =	23.250
Throat Diameter =	9.842
Dimensions By: DANIEL	

MEAN - 0.9985 ABOVE THROAT  
REYNOLDS # 2000000

TAP SET # B  
24" FLOW NOZZLE ASSEMBLY  
TAG NUMBER: .9 FWCFS1-FE-0010  
DANIEL INDUSTRIES, INC.  
PO NUMBER: 77258  
OCTOBER 1, 1984

ARL

IP14\_000925



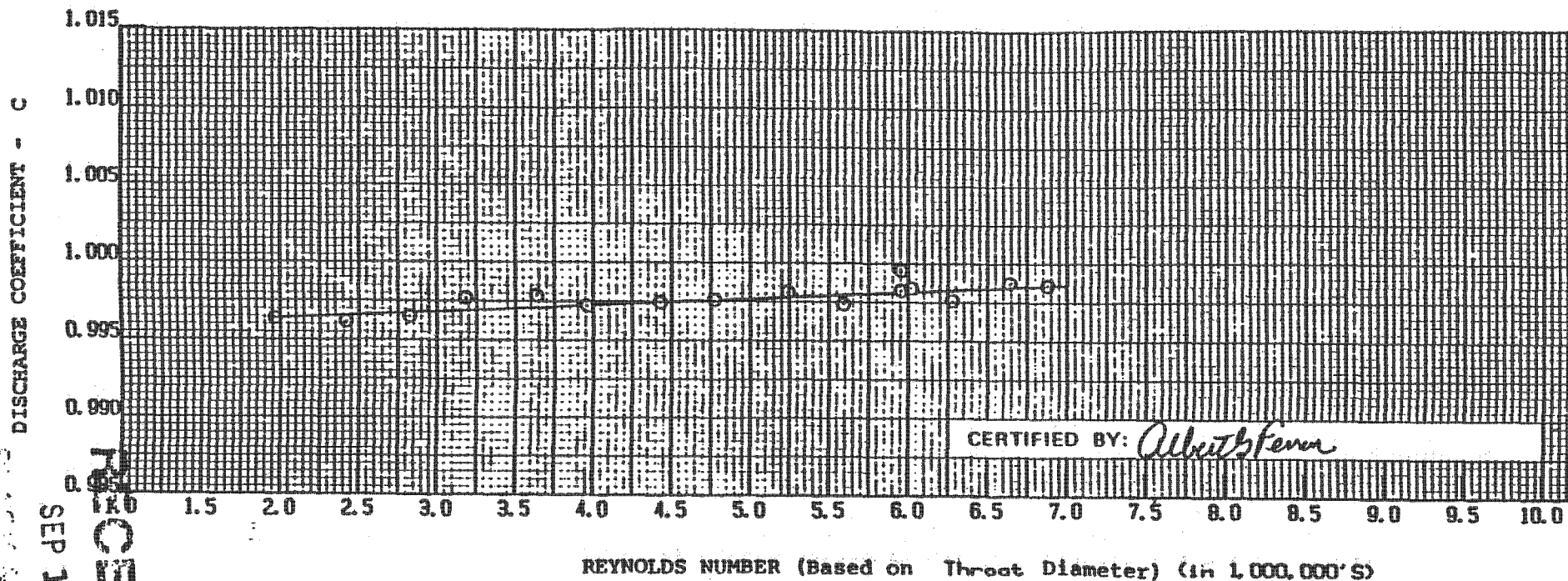
$q_a = C K_M \sqrt{h}$	
$q_a$ = Actual Flow Rate (ft <sup>3</sup> /sec)	
C = Discharge Coefficient - Dimensionless	
h = Pressure Differential in Feet of Water at Run Temperature	
$K_M$ = Meter Constant = $\frac{a\sqrt{2g} \times F_a}{\sqrt{1 - \beta^4}}$	2.7432
$F_a$ = Thermal Expansion Factor =	1.0006
$a$ = Throat Area (ft <sup>2</sup> ) =	0.3329
g = Local Acceleration of Gravity (ft/sec <sup>2</sup> )	32.163
$\beta$ = Dimensionless Ratio of Throat to Pipe Diameter =	0.4836
Upstream Diameter =	16.142
Throat Diameter =	7.8060
Dimensions By: B. I. F.	

TAP SET # 1  
 20" PTC-6 TEST SECTION  
 SERIAL NUMBER: C90916-1  
 B. I. F.  
 PO NUMBER: 85797-KO  
 SEPTEMBER 16, 1985

ARL

IP14\_000926





SEP 16 1985

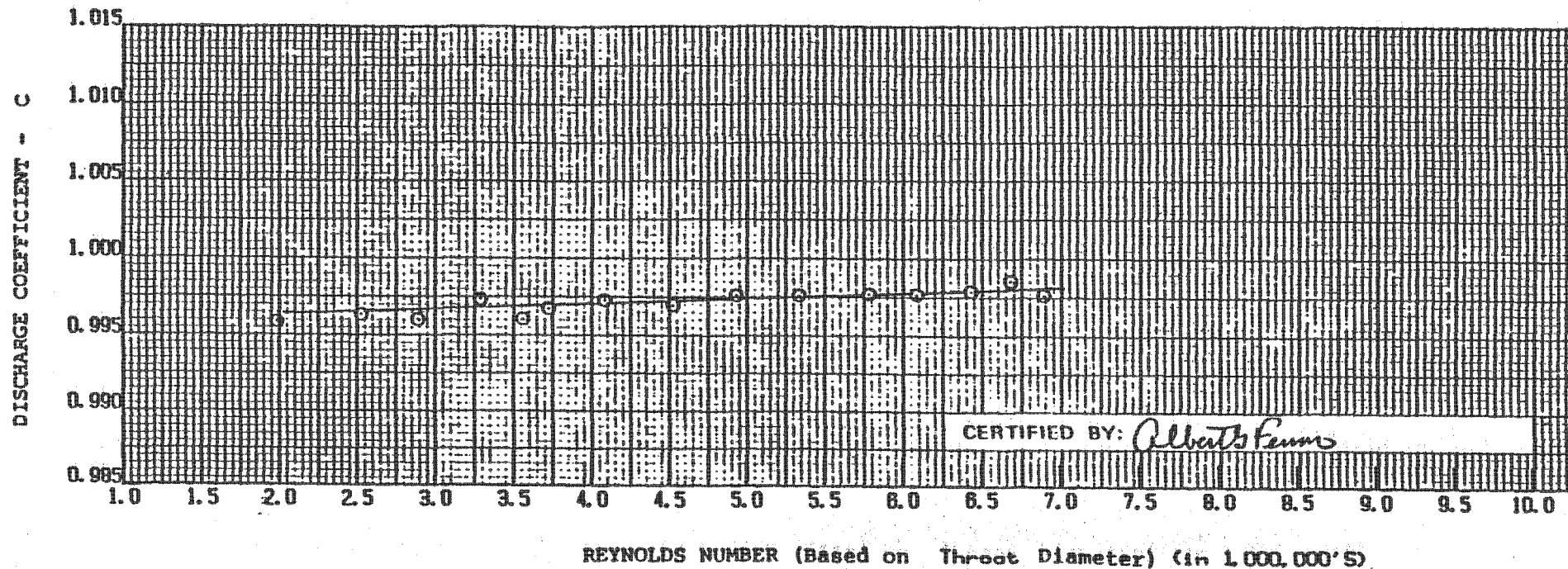
RECEIVED

$q_a = C K_M \sqrt{h}$	
$q_a$ - Actual Flow Rate (ft <sup>3</sup> /sec)	
C - Discharge Coefficient - Dimensionless	
h - Pressure Differential in Feet of Water at Run Temperature	
$K_M$ - Meter Constant = $\frac{a\sqrt{2g} \times F_a}{\sqrt{1 - \beta^4}}$	2.7262
$F_a$ - Thermal Expansion Factor =	1.0006
a - Throat Area (ft <sup>2</sup> ) =	0.3325
g - Local Acceleration of Gravity (ft/sec <sup>2</sup> )	32.163
$\beta$ - Dimensionless Ratio of Throat to Pipe Diameter =	0.4525
Upstream Diameter =	17.254
Throat Diameter =	7.8080
Dimensions By: DANIEL	

TAP SET # A  
 18" FLOW NOZZLE ASSEMBLY  
 SERIAL NUMBER: 85-110134  
 DANIEL INDUSTRIES INCORPORATED  
 PO NUMBER: 1-PO-81459  
 MAY 15, 1985

ARL

IP14\_000927



$q_a = C K_M \sqrt{h}$	
$q_a$ = Actual Flow Rate (ft <sup>3</sup> /sec)	
C = Discharge Coefficient - Dimensionless	
h = Pressure Differential in Feet of Water at Run Temperature	
$K_M$ = Meter Constant = $\frac{a\sqrt{2g} \times F_a}{\sqrt{1 - \beta^4}}$	2.7255
$F_a$ = Thermal Expansion Factor =	1.0008
a = Throat Area (ft <sup>2</sup> ) =	0.3324
g = Local Acceleration of Gravity (ft/sec <sup>2</sup> )	32.163
$\beta$ = Dimensionless Ratio of Throat to Pipe Diameter =	0.4523
Upstream Diameter =	17.259
Throat Diameter =	7.8070
Dimensions By: DANIEL	

TAP SET # A  
 18" FLOW NOZZLE ASSEMBLY  
 SERIAL NUMBER: 85-110135  
 DANIEL INDUSTRIES INCORPORATED  
 PO NUMBER: 1-PO-81459  
 MAY 15, 1985

ARL

IP14\_000928